

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 Gas Company for authority to	)	
increase its rates for the distribution	)	Case No. U-21291
of natural gas and for other relief	)	
_____	)	

**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 4, 2024.

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 September 25, 2024, 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 7, 2024.

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

September 4, 2024  
Lansing, Michigan

\_\_\_\_\_  
Jonathan F. Thoits  
Administrative Law Judge

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In the matter of the application of )  
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of natural gas and for other relief )  
\_\_\_\_\_ )

Case No. U-21291

**PROPOSAL FOR DECISION**

I.

**PROCEDURAL HISTORY**

On January 8, 2022, DTE Gas Company (DTE) filed a natural gas rate application and supporting direct testimony and exhibits asserting an expected revenue shortfall of \$266 million based on a projected twelve-month test year ending September 30, 2025 and seeking a net increase to customer rates of approximately \$160 million and other relief, because \$106 million of the revenue deficiency is already reflected in rates via the existing Infrastructure Recovery Mechanism (IRM) surcharge.<sup>1</sup>

DTE, Staff, and potential intervenors attended the February 5, 2024, prehearing conference. The Michigan Attorney General (Attorney General) intervened by right and intervention was granted to the Association of Businesses Advocating Tariff Equity (ABATE); the Retail Energy Supply Association (RESA); Michigan Environmental

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<sup>1</sup> This revenue increase amount has since been revised downward by DTE to \$262 million due to a \$2.9 million adjustment to the revenue requirement. DTE Initial Brief, p. 1, Attachment A, p. 1.

Counsel, Citizens Utility Board of Michigan (CUB), Sierra Club, and Natural Resources Defense Council (collectively, MNSC); Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, Vote Solar (collectively, Clean Energy Organizations (CEO); Urban Core Collective, We Want Green Too, and Soulardarity (collectively, Frontline Organizations (FLO); City of Ann Arbor; Billerud Americas Corporation, Dearborn Industrial Generation LLC; and Michigan Power Limited Partnership (MPLP). The parties agreed to a schedule complying with the time limits of MCL 460.6a.<sup>2</sup> The parties also stipulated to entry of DTE's proposed Protective Order, which was entered on February 12, 2024, pursuant to which certain testimony and exhibits relied upon by the parties were deemed Confidential Information and entered under a separate record.

In keeping with the schedule established at the prehearing, Staff and various intervenors filed direct testimony and supporting exhibits on May 7, 2024 and rebuttal testimony and supporting exhibits on May 29, 2024. Various parties filed refiled, revised, restated, adopted or amended testimony and/or exhibits on the dates indicated in the case docket.

Evidentiary hearings were held on June 20, June 21, and June 24, 2024. Four witnesses appeared and were cross-examined on their testimony, while the testimonies of the remaining witnesses were bound into the record.

During the hearing, DTE offered the testimony of the following witnesses:

1. Emil Abona, Manager of Strategy and Special Projects;

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<sup>2</sup> Section 6a(5) of Public Act 286 requires the Commission to issue its final order within 10 months following receipt of a complete rate case filing, lest the application be considered approved. MCL 460.6a(5).

2. Michael Brennan, Principal Environmental Engineer – Environmental Management;
3. Jaison Busby, IT Director – Power Supply, Energy Gas and Innovation;
4. George Chapel, Manager – Market Forecasting;
5. Michael Cooper, Director – Compensation, Benefits & Wellness;
6. Henry J. Decker, Vice President – Gas Sales and Supply;
7. Kelly Fedele, Director –Asset Management and Engineering;
8. Michael Hatsios, Director – Customer Transformation;
9. Eric Janness, Director – Gas Renewal Program;
10. Scotty Kehoe, Director – Greater Michigan Gas Operations;
11. Timothy Krysinski, Principal Project Manager – Regulatory Affairs;
12. Tim Lepczyk, Assistant Treasurer and Director – Corporate Finance;
13. Jason Sparks, Director of Revenue Management and Protection;
14. Rajan Telang, Director, Regulatory Affairs;
15. Theresa Uzenski, Manager – Regulatory Accounting;
16. Kirk Vangilder, Principal Financial Analyst – Regulatory Economics;
17. Dr. Bente Villadsen, Principal – The Brattle Group;
18. Sherri Wisniewski, Director – Tax Accounting;

Through these witnesses, DTE entered into evidence Exhibits A-1 through A-5, A-11 through A-22, A-24 through A-38 inclusive.

Staff offered testimony from the following Staff personnel:

1. Nicholas M. Revere;
2. Cynthia L. Creisher;
3. Danielle R. Rogers;

4. Madison S. Todd;
5. Joseph E. Ufolla;
6. James E. LaPan;
7. Theresa L. McMillan-Sepkoski;
8. Charles E. Putnam;
9. Kevin S. Krause;
10. Robert F. Nichols II;
11. Shannon Rueckert;
12. Kevin P. Spence;
13. Justin J. Hecht;
14. Nyrhe U. Royal;
15. Elaina M. Braunschweig.

Through these witnesses, Staff entered Exhibits S-1 through S-3, S-3.0, S-4, S-6, S-6.0, S-8.0 through S-8.1, S-9.0 through S-9.5, S-10.0 through S-10.8, S-11.1 through S-11.6, S-12.0 through S-12.3, S-13.1 through S-13.1 through S-13.6, S-14.0, S-15.

The Attorney General provided the testimony of Sebastian Coppola, an independent business consultant, and Exhibits AG-1 through AG-73.

ABATE provided the testimony of Jessica A. York, Colin T. Fitzhenry, and Christopher C. Walters, and Exhibits AB-1 through AB-20.

FLO provided the testimony of Jackson Koeppel, Justin Schott, Sergio Cira-Reyes and Toyia Watts, and Exhibits FLO-1 through FLO-47, FLO-101 through FLO-167, FLO-201 through FLO-242, FLO-301 through FLO-305, FLO-401 through FLO-414.

CUB provided the testimony of Ram Veerapaneni and Matt Bandyk and Exhibits CUB-1 through CUB-9.

MNSC provided the testimony of Dr. Asa S. Hopkins and Alice Napoleon and Exhibits MEC-1 through MEC-42, MEC-45 through MEC-46, MEC-51 through MEC-61, MEC-69 through MEC-70, MEC-74, MEC-77 through MEC-78, MEC-80, MEC-82 through MEC-83, MEC-90 through MEC-93, MEC-97 through MEC-99, MEC-101 and MEC-104.

MPLP provided the testimony of Brian C. Collins and Exhibits MPL-1 through MLP-10.

CEO provided the testimony of Bradley Cebulko and Saad Siddique and Exhibits CEO-1 through CEO-45.

The City of Ann Arbor provided the testimony of Robert C. Ackley, Skye Stewart, and Dr. Melissa Stults and Exhibits AA-1 through AA-43.

Dearborn Industrial Generation offered Exhibits DIG-1 through DIG-6.

In accordance with the established schedule, DTE, Staff, the Attorney General, ABATE, Ann Arbor, MPLP, MNSC, CEO, and FLO filed initial briefs on July 16, 2024. These same parties also filed reply briefs on July 31, 2024.<sup>3</sup>

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<sup>3</sup> The February 8, 2024 scheduling memo filed in this matter set forth instructions for the briefs, including that a) each brief shall contain a table of contents, listing the subject headings of the brief, including the points of argument, in the order of presentation according to the points of argument set forth by the utility; b) all parties shall include the same points of argument headings and subheadings in the same order as set forth by the utility in its list of points of argument; and c) at the beginning of each argument section of the brief, the brief shall list the references to the record (name of the witness(es), the transcript citation(s), and the exhibit number(s)) which relate to the issue being briefed. The scheduling memo also provided that "if any brief is determined by the ALJ to not substantially comply with these requirements, the ALJ may order the party who filed the brief to file a supplemental brief within a specified time correcting the deficiencies, or may disregard or strike the non-conforming brief." The briefs filed by the following parties failed to comply with these instructions: DTE, Staff, the Attorney General, ABATE, Ann Arbor, MPLP, CEO, and FLO. As such, parts of various non-conforming briefs were disregarded. In the future, any such non-conforming brief shall be stricken from the record and the party shall be ordered to file a supplemental conforming brief. *See, Fisher v City of Ann Arbor*, unpublished per curiam opinion of the Court of Appeals, issued January 30, 2014 (Docket No. 313634), ("We also decline to address the issue raised by petitioner in her supplemental brief because the brief does not conform to the requirements of U-21291

In order to ensure compliance with the statutorily imposed timeframe for deciding this case, MCL 460.6a(5), the evidence and arguments necessary for a reasoned analysis of the disputed issues are expressly addressed in the Proposal for Decision. However, all the evidence presented in this case was considered, along with the arguments made by the parties based on the evidence.

## II.

### **THE COMPANY'S APPLICATION**

DTE Gas, a subsidiary of DTE Energy Company, is a public utility engaged in the acquisition, storage, transportation, distribution and sale of natural gas and other related services to approximately 1.3 million residential, commercial and industrial customers within the State of Michigan.<sup>4</sup> DTE is currently providing service to its retail natural gas transportation, storage and distribution customers under rates, terms and conditions established in the Commission's order issued on December 9, 2021 in Case No. U-20940, with the rates having been implemented effective for service rendered on or after January 1, 2022.<sup>5</sup>

DTE states that the proposed revenue increase described in this filing is necessary to allow DTE to continue providing safe and reliable gas service, to meet customers' service quality expectations, and to allow DTE a reasonable opportunity to recover its

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MCR 7.212(G). MCR 7.212(I)"); Case No. U-20322, Order, September 26, 2019, p. 5-6. ("The Commission's Rules of Practice and Procedure do not contain specific instructions for briefing in contested cases before the Commission. Therefore, the ALJ, as the presiding officer in a contested proceeding before the Commission, may rely on the Michigan Court Rules. . . . If the parties choose not to comply with the administrative law judge's legally enforceable directives, the Commission acknowledges the administrative law judge's discretion to enforce those directives pursuant to law and the Michigan Court Rules.")

<sup>4</sup> Application, par. 1.

<sup>5</sup> Id., par. 2.

costs of operation including a reasonable rate of return beginning in October 2024.<sup>6</sup> DTE asserts that additional revenues are necessary to pay for the impacts of extensive infrastructure and IT investments, additional projected operation and maintenance expense required to ensure reliability of the system, the safety of customers, compliance with State and Federal requirements, collective bargaining and market-driven wage increases, and lower forecasted sales.<sup>7</sup>

DTE states that its historical year presentation reflects the 12-month period ended December 31, 2022, and that its rate relief request is based upon the 12-month period ended December 31, 2022, normalized historical test year adjusted for known and measurable changes to arrive at DTE's October 1, 2024 through September 30, 2025 projected test year.<sup>8</sup>

DTE is proposing to continue the RDM approved in Case No. U-20940 as a "simple revenue tracker" that reconciles Case No. U-21291 distribution revenue and is proposing to continue the Infrastructure Recovery Mechanism (IRM) in this proceeding with adjustments.<sup>9</sup>

DTE is requesting a Return on Equity (ROE) of 10.25%, capital structure of 48.5% debt and 51.5% equity, and application of annual inflation factors of 3.2% in 2023, 2.9% in 2024, and 2.2% in 2025.<sup>10</sup> DTE is requesting authority to recover Manufactured Gas Plant (MGP) expenses in setting its projected MGP amortization for the projected year.<sup>11</sup> DTE is requesting that the Commission approve specific accounting authority and is

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<sup>6</sup> Id., par. 4.

<sup>7</sup> Id.

<sup>8</sup> Id., par. 7.

<sup>9</sup> Id., par. 8,9.

<sup>10</sup> Id., par. 10.

<sup>11</sup> Id., par. 11.

asking for an increase in the amount of the Low-Income Assistance (LIA) credit from \$30 per month to \$40 per month.<sup>12</sup> DTE is seeking the continuation of regulatory asset treatment for Pension and Other Post-Employment Benefit (OPEB) financing costs and is asking for deferral accounting for the projected increase in leak detection and repair costs if the Commission does not allow for current recovery.<sup>13</sup>

### III.

#### TEST YEAR

A test year is the starting point for establishing just and reasonable rates for both the regulated utility and its customers.<sup>14</sup> A test year is used by the Commission to establish representative levels of revenues, expenses, rate base, and capital structure for use in the rate-setting formula.<sup>15</sup> The selection of an appropriate test year has two components: determining a 12-month period to be used for setting the utility's rates, and determining how the Commission should establish values for the various revenue, expense, rate base, and capital structure components used in the rate-setting formula.<sup>16</sup> The Commission may use different methods in establishing values for these components, provided that the result is a determination of just and reasonable rates for the company and its customers.<sup>17</sup>

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. In a case where a utility decides to base its filing on a fully projected

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<sup>12</sup> *Id.*, par. 12.

<sup>13</sup> *Id.*

<sup>14</sup> Case Nos. U-15768 and U-15751, Opinion and Order, January 11, 2010, p. 9.

<sup>15</sup> *Id.*

<sup>16</sup> *Id.*

<sup>17</sup> *Id.*

test year, the utility bears the burden to substantiate its projections.<sup>18</sup> 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.<sup>19</sup>

In this proceeding, DTE proposed using the 12-month period ending September 30, 2025 as the projected test year, and the 12-month period ended December 31, 2022 as the historical year.<sup>20</sup>

ABATE asserts that DTE's recent rate increases have been driven by the use of projected rather than historical test years for ratemaking and aggressive capital expenditures coupled with the filing of frequent rate cases.<sup>21</sup> Ms. York states that in this proceeding, and in four out of five of DTE's most recent previous rate filings, DTE has reported a revenue sufficiency for its filed historical test year indicating recurring instances of DTE earning revenues in excess of its authorized amount due to the continuing use of a projected test year.<sup>22</sup> She adds that given this track record with respect to the use of a projected test year, the Commission should require DTE to use its proposed historical test year as the basis of its revenue requirement in this proceeding.<sup>23</sup> She asserts that given that DTE is reporting a revenue sufficiency of \$35.7 million for its historical test year in this proceeding, this would limit DTE's revenue requirement increase in this proceeding to no more than \$105.6 million – the revenue requirement amount that DTE has proposed

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<sup>18</sup> *Id.*

<sup>19</sup> *Id.*

<sup>20</sup> DTE's Application, par. 7.

<sup>21</sup> 4 Tr 1260.

<sup>22</sup> *Id.*

<sup>23</sup> *Id.*

to roll into base rates from its current IRM Surcharge based on DTE's proposed ROE and equity ratio.<sup>24</sup>

Ms. York states 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.<sup>25</sup> She adds that this has had and continues to have several adverse impacts on customers.

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. . .

Finally, the use of a projected test year greatly handicaps the Commission Staff ("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. . .<sup>26</sup>

Ms. York asserts that DTE's projected bridge period capital expenditures and forecasted test year expenses and capital expenditures are not known and measurable changes to its historical test year.<sup>27</sup> She adds that 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 are highly speculative and include capital expenditures and expenses that DTE has not irrevocably committed to make.<sup>28</sup>

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<sup>24</sup> Id.

<sup>25</sup> 4 Tr 1263.

<sup>26</sup> 4 Tr 1263-1264.

<sup>27</sup> 4 Tr 1264.

<sup>28</sup> Id.

Ms. York states that there is no evidence presented in this case that DTE experienced a revenue deficiency in calendar year 2023.<sup>29</sup> She adds that the Commission has stated that the utility bears the burden to substantiate its projections, and that 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 Commission may choose an alternative method for determining the projection.”<sup>30</sup> She asserts that that alternative method should be the use of the historical test year amount for that item adjusted for only known and measurable changes to the amount for that item.<sup>31</sup>

Ms. York states that if the Commission decides to allow DTE to use a projected test year for this proceeding, she recommends that the Commission a) be much more vigilant with respect to ensuring the expenses and investments being projected by DTE for its projected test year are truly expenses and investments that are necessary to provide reliable service at lowest reasonable cost, b) ensure that DTE is irrevocably committed to incur its projected expenses and investments or otherwise cannot avoid them, and c) ensure that DTE’s projected investments and expenses are precisely quantified by DTE with respect to both amount and the specific quarter in which DTE will incur these investments and expenses.<sup>32</sup>

In rebuttal, Mr. Telang asserts that DTE has utilized, and the Commission has approved, the current projected test year methodology for all DTE’s rate cases for over a

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<sup>29</sup> 4 Tr 1266.

<sup>30</sup> 4 Tr 1266-1267, citing Case No. U-15645, Order, November 2, 2009, p. 9.

<sup>31</sup> 4 Tr 1267.

<sup>32</sup> 4 Tr 1268.

decade.<sup>33</sup> He adds that the Commission previously stated that “the Commission’s approval of projected test years is permissible under MCL 460.6a and challenges to the use of a projected test year have been well-settled by the Court of Appeals.”<sup>34</sup> He asserts that DTE provides substantial support and justification for its projected expenditures in every rate case.<sup>35</sup> He adds that since new rates cannot be implemented until after a final order is issued in a rate case, it makes sense that the projected test year begins at or about the time that a final rate case order is expected.<sup>36</sup>

This PFD recommends that the Commission adopt the 12-month period ending September 30, 2025 proposed by DTE as the projected test year. The time period of the projected test year in this case is in similar proximity to the date of this case filing and the expected date of the Commission’s order in this case as previously projected test years were with the filing and order dates in past cases in which the Commission approved the projected test year.<sup>37</sup> Moreover, as MCL 460.6a permits other parties to propose appropriate costs and revenues on a basis other than DTE’s projections, it is incumbent on the party proposing a different test period to provide the revenue and expense amounts corresponding to that period, as well as evidence to show that the alternative test period is more just and reasonable than the utility’s proposal or any proposal by any other party.<sup>38</sup>

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<sup>33</sup> 4 Tr 1874.

<sup>34</sup> *Id.*, citing Case No. U-21297, Order, December 1, 2023, p. 9.

<sup>35</sup> *Id.*

<sup>36</sup> 4 Tr 1875.

<sup>37</sup> See, Case Nos. U-20561 and U-20162.

<sup>38</sup> See, Case No. U-15645, Order, November 2, 2009, p. 9 (“[T]he Commission’s expectation is that the parties will fully document the basis for their test year projections by offering into evidence detailed supporting explanations and underlying assumptions rooted in expected business, financial, and economic circumstances. . . . When necessary, parties should provide competing projections, with a similar basis of support. . . . Historical data may play a role, but ordinarily will not be the controlling factor except in circumstances that clearly demonstrate that it is a more fair and reasonable reflection of the utility’s cost of service, relative to projected data.”)

In this instance, neither ABATE nor MNSC have specifically identified or explained which of DTE's estimates are flawed, nor otherwise shown that the projected test year is "set so far removed from circumstances actually in view as to render it less than workable."<sup>39</sup>

#### IV.

#### RATE BASE

Rate base consists of total utility plant (i.e. the capital invested in all plant in service, plant held for future use, and construction work in progress (CWIP), less the company's depreciation reserve (consisting of its accumulated depreciation, amortization, and depletion), plus the utility's working capital requirements.<sup>40</sup>

In this case, DTE projects its rate base for the test year at \$6,944 million, consisting of \$6,071.1 million of total utility property and \$868.7 million of working capital.<sup>41</sup>

Mr. Hecht states that Staff presents a total projected rate base of \$6,928,530,000, which is a decrease of \$15,433,000 from DTE's \$6,943,963,000 projection.<sup>42</sup> He adds that Staff presents a projected total utility plant of \$8,782,212,000, which is a decrease of \$10,304,000 from DTE's \$8,792,516,000 projection.<sup>43</sup> He states that the \$10,304,000 reduction is the corresponding impact to plant in service resulting from Staff adjustments to DTE's historic and projected capital expenditures.<sup>44</sup>

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<sup>39</sup> *In re Consumers Energy Company to Increase Rates*, 338 Mich App 239, 245, 979 NW2d 702 (2021) ("RCG challenges the evidentiary basis for the chosen test year only by complaining generally that, because it extends 22 months beyond the date on which the rate case was filed, it has resulted in speculative and exaggerated forecasts concerning Consumers' future costs and investments. RCG does not specifically identify or explain what estimates are flawed, nor does it offer any alternative calculations.")

<sup>40</sup> MPSC Case No. U-17735, November 19, 2015, Order, p. 7.

<sup>41</sup> DTE initial brief, p. 16; Ex. A-12, Sch. B1.

<sup>42</sup> 4 Tr 1746; Ex. S-2, Sch. B-1; Ex. A-12, Sch. B-1.

<sup>43</sup> *Id.*

<sup>44</sup> *Id.*, Figure 1.

### **Adjusted Total Rate Base**

DTE states that the rate base adjustments it is adopting pertain to 1) a reduction in working capital to adjust the deferred incentive compensation regulatory asset to reflect actual 2023 results and 2) a reduction in working capital for a Treasury clearing account balance included in error.<sup>45</sup> DTE Gas's total rate base, as adjusted in its brief, for the projected period ending November 30, 2024, is reduced from \$6,944.0 million to \$6,939.8 million.<sup>46</sup>

### **Capital Expenditures**

At the outset, it is noted that the Attorney General critically assesses DTE's requested rate increase. Mr. Coppola states that in this general rate case, DTE Gas proposes capital expenditures of \$730.6 million for 2023, \$559 million for the 9 months ending September 2024, and an additional \$465 million for the 12 months ending September 2025.<sup>47</sup> In addition, Mr. Coppola states that DTE proposes to spend \$354 million in 2025 on the IRM program with similar amounts in the subsequent four years.<sup>48</sup> He adds that the total proposed capital expenditures over this 36-month period are nearly \$2.1 billion, which expenditures follow capital expenditures of \$1.9 billion made during the prior three years from 2020 to 2022.<sup>49</sup> He asserts that until 2012, DTE was able to keep capital expenditures below \$200 million annually, and that by 2016, annual capital expenditure had doubled and eight years later has nearly doubled again, to \$753 million.<sup>50</sup>

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<sup>45</sup> DTE initial brief, p. 16.

<sup>46</sup> Id.

<sup>47</sup> 4 Tr 1430.

<sup>48</sup> Id.

<sup>49</sup> Id.

<sup>50</sup> 4 Tr 1431.

Mr. Coppola asserts that the capital expenditures have fueled an alarming increase in rate base, with rate base having been growing at double digit rates in recent years, while DTE is proposing to increase rate base again in this rate case by 22% to \$6.9 billion, which is more than double the amount of rate base DTE had 9 years ago.<sup>51</sup> He asserts that the current trend has significant negative implications for customer bills.<sup>52</sup>

Mr. Coppola states that there are two main drivers of the dramatic increase in capital expenditures and rate base in the last ten years.<sup>53</sup> First, he states that replacement of aging infrastructure and new capital spending to address market growth have required an increase in capital expenditures, which may have accelerated investment to some degree.<sup>54</sup> Noting that DTE continues to propose ever-increasing capital expenditures to replace cast iron mains, service lines and related facilities, some of this work he states is necessary and must be done, he asserts that DTE has intensified the pace of replacement of pipelines and other facilities without sufficient engineering analysis to support the increase in capital expenditures.<sup>55</sup> He adds that DTE also seems to be experiencing moderate customer growth in its market area, but asserts that moderate customer growth has existed in prior years.<sup>56</sup>

Second, Mr. Coppola states that perhaps a bigger driver, the replacement of aging gas infrastructure has given DTE an opportunity to accelerate rate base growth in order to increase earnings growth, noting that for utility companies, earnings growth is directly

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<sup>51</sup> Id.

<sup>52</sup> Id.

<sup>53</sup> 4 Tr 1432.

<sup>54</sup> Id.

<sup>55</sup> Id.

<sup>56</sup> 4 Tr 1433.

related to rate base growth.<sup>57</sup> He asserts that large increases in capital expenditures result in double digit increases in rate base, which in turn fuels earnings growth, dividend growth, and stock price appreciation for shareholders.<sup>58</sup> He states that DTE's parent company, DTE Energy, has been quite clear and aggressive in communicating to investors and securities analysts its goal of increasing operating earnings at the gas utility at an average annual rate of 7%, noting that an April 2024 Investor Presentation shows this drive to increase earnings through increased capital spending at the utility.<sup>59</sup> He asserts that for a utility such as DTE Gas with limited sales and revenue growth, the increase in earnings comes almost entirely from the increase in capital expenditures and rate base.<sup>60</sup>

Noting that DTE has proposed to increase residential rates in this rate case by 9%, Mr. Coppola asserts that, if we assume that DTE continues its current pace of capital expenditures with bi-annual rate cases and rate increases, the average residential total annual gas bill in 10 years will increase by nearly 50%, from \$954 in 2022 to \$1,481 in 2032.<sup>61</sup> He states that the compounding effect of large additions to rate base will continue to increase customer rates to unaffordable levels for many customers, particularly those in fixed and lower income brackets, a trend which is not sustainable for customers.<sup>62</sup> He concludes that to avoid bill affordability problems, DTE needs to moderate and be more selective in its capital spending in the coming years.<sup>63</sup>

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<sup>57</sup> Id.

<sup>58</sup> Id.

<sup>59</sup> Id.; Ex. AG-1.

<sup>60</sup> Id.

<sup>61</sup> 4 Tr 1434, Table 4.

<sup>62</sup> 4 Tr 1435.

<sup>63</sup> Id.

In his analysis of DTE's forecasted capital expenditures and in projecting adjusted capital expenditures for 2024 and the projected test year, where applicable, he applied an inflation factor to the historical cost base to reflect inflationary cost pressure that DTE may face in those years.<sup>64</sup> He states that the inflation factors are 2.6% for 2024 and 2.2% for 2025, which reflect the increase in the forecasted Consumer Price Index for the 2024-2025 periods published on March 1, 2024.<sup>65</sup>

For purposes of this PFD, DTE's projected capital expenditures are broken down into the following categories: a) Gas Delivery Plan, b) Routine Capital Spending, c) Gas Information Technology (IT) Spending, Large Capital Projects, and Infrastructure Recovery Mechanism.

### **Gas Delivery Plan**

DTE requests cost recovery of capital expenditures that will be utilized for its natural gas system. DTE states that beginning January 1, 2023, through the end of the projected test year on September 30, 2025, DTE will have incurred approximately \$1.8 billion in capital expenditures, excluding IRM expenditures.<sup>66</sup> DTE states that beginning January 1, 2025, DTE plans to recover IRM expenditures contemporaneously through the IRM surcharge, similar to what the Commission has approved in the past five general rate cases.<sup>67</sup> DTE states that the \$1.8 billion in capital expenditures can be broken out into four categories; Routine Plant (\$817.1 million), Large Capital Projects (\$184.3 million),

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<sup>64</sup> Id.

<sup>65</sup> 4 Tr 1435-1436. Citation omitted.

<sup>66</sup> DTE initial brief, p. 17, citing 4 Tr 1898.

<sup>67</sup> Id.

Infrastructure Recovery mechanism (\$720.5 million) and Das Information Technology (\$33.1 million).<sup>68</sup>

### **Routine Capital Spending**

Mr. Abona states that DTE Gas has made or will make \$817.1 million of routine capital expenditures from January 1, 2023 (the end of the historical test year) to September 30, 2025 (the end of the projected test year).<sup>69</sup> He adds that DTE Gas's annual 2023-2025 planned routine capital expenditures are, on average, \$48.3 million higher per year than the 2018-2022 \$247.0 million five-year average, with the amount above the five-year average being driven by \$45.3 million of Distribution Plant, \$2.0 million of Transmission Plant, \$0.1 million of Storage Plant, and \$0.87 million of General Plant expenditures.<sup>70</sup>

DTE states that routine distribution plant capital expenditures include unplanned main renewals, public improvement, service abandonments, service alterations, service renewals, system reliability, communications & control – meters, advance metering infrastructure (AMI), revenue protection, and new market attachments.<sup>71</sup>

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$650.4 million of routine distribution plant capital expenditures.<sup>72</sup> He adds that DTE 2023-2025 planned routine distribution plant expenditures are on average \$45.3 million higher per year than the 2018-2022 \$189.6 million five-year average.<sup>73</sup>

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<sup>68</sup> DTE initial brief, p. 17-18, citing 4 Tr 1899.

<sup>69</sup> 3 Tr 331; Ex. A-12, Sch. B5.1.

<sup>70</sup> Id.

<sup>71</sup> 3 Tr 332-333.

<sup>72</sup> 3 Tr 334; Ex. A-12, Sch. B5.1.

<sup>73</sup> Id., Table 1.

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$18.1 million of unplanned main renewal capital expenditures.<sup>74</sup> He adds that on average, DTE Gas expects its 2023-2025 routine unplanned main renewal expenditures to be \$0.7 million higher per year than the 2018-2022 \$5.8 million five-year average.<sup>75</sup>

Mr. Coppola states that DTE indicates that historical feet of main replaced has been rather consistent in the past 3-years, ranging from 13,455 to 17,980 feet and averaging approximately 15,000 feet annually, and that the three year average of main renewed is only slightly higher than the 14,200 feet renewed on average over the past five years.<sup>76</sup> Mr. Coppola states that based on the more recent 3-year average, he determined that DTE incurred capital spending for main renewals of \$7,313,000 on average annually over the 2021 to 2023 period, and that after adjusting for inflation, he determined that the forecasted capital expenditures for main renewals for 2024 should be \$7,503,000 and \$5,627,000 for the 9 months ending September 2024.<sup>77</sup> He adds that DTE forecasted capital expenditures of \$7,019,000 for the 9 months ending September 2024, which he asserts is excessive and overstated by \$1,392,000.<sup>78</sup> He states that for the projected test year ending September 2025, he finds DTE's forecasted capital expenditures to be in line with historical spending levels.<sup>79</sup> Thus, he recommends that the

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<sup>74</sup> 3 Tr 335; Ex. A-12, Sch. B5.1.

<sup>75</sup> Id.

<sup>76</sup> 4 Tr 1437.

<sup>77</sup> Id.; Ex. AG-3, Ex. Ag-4.

<sup>78</sup> 4 Tr 1437-1438.

<sup>79</sup> 4 Tr 1438.

Commission remove the \$1,392,000 from DTE's forecasted capital expenditures for the 9 months ending September 2024 included in rate base.<sup>80</sup>

This PFD notes that DTE does not appear to have offered any rebuttal to Mr. Coppola's testimony.<sup>81</sup> This PFD agrees with the Attorney General that DTE's proposed expenses appear to be excessive. As such, this PFD recommends that the Commission adopt the Attorney General's proposed \$1,392,000 disallowance.

### **Service Renewals**

Mr. Abona states that From January 1, 2023, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$32.5 million of service renewal capital expenditures.<sup>82</sup> He adds that on average, DTE Gas expects its 2023-2025 routine service renewal expenditures to be \$0.97 million lower per year than the 2018-2022 \$12.8 million five-year average.<sup>83</sup>

Ms. Creisher states that the service renewals capital expenditures are used for the reconnection of previously abandoned customer service lines.<sup>84</sup> She adds that Staff does not support DTE's proposed capital expenditures for service renewals.<sup>85</sup> Noting that DTE's cost per unit of \$3,716 for service renewals completed in 2023, which is \$1,114 less than DTE projected in its original filing, Staff recommends that the 2024 and 2025 cost per unit for service renewals should be adjusted based on a three-year historical

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<sup>80</sup> Id.

<sup>81</sup> See 3 Tr 384-402; DTE initial brief.

<sup>82</sup> 3 Tr 345; Ex. A-12, Sch. B5.1.

<sup>83</sup> Id., Table 5.

<sup>84</sup> 4 Tr 1788.

<sup>85</sup> 4 Tr 1789.

average from 2021 through 2023.<sup>86</sup> Staff recommends that the projected capital expenditure for the 2024 and 2025 program years for service renewals be adjusted based on the three-year average cost per unit for service renewals of \$4,332, with Staff using an allocation of 78% of the capital expenditures occurring in the first nine months of each calendar year, thus, recommending capital expenditures of \$8,615,012 for the nine months ending September 30, 2024, and \$11,032,083 for the test year ending September 30, 2025.<sup>87</sup>

This PFD notes that DTE does not appear to rebut Staff's statements or recommendations. As such, this PFD agrees with Staff and recommends that the Commission adopt Staff's recommendations.

### **Revenue Protection**

Mr. Abona states that revenue protection capital expenditures arise from cut and caps associated with theft and non-payment of gas service, and include service renewal costs associated with reconnects.<sup>88</sup> He states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$6.5 million of revenue protection program capital expenditures.<sup>89</sup>

### **New Market Attachments**

Mr. Abona states new market attachments capture the cost to design, procure, and install new natural gas facilities serving residential, commercial, and industrial

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<sup>86</sup> Id.

<sup>87</sup> 4 Tr 1790; Ex. S-10.0.

<sup>88</sup> 3 Tr 358.

<sup>89</sup> 3 Tr 359, Table 8.

customers.<sup>90</sup> He states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$245.0 million of new market attachments capital expenditures.<sup>91</sup> He adds that on average, DTE Gas expects its 2023-2025 routine New Market Attachment expenditures to be \$3.8 million lower per year than the 2022 historical year spend of \$92.5 million.<sup>92</sup>

### **Permits and Other Adjustments**

Mr. Abona states from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$2.1 million of Permits and Other Adjustments capital expenditures.<sup>93</sup> He adds that on average, DTE Gas expects its 2023-2025 planned routine Permits and Other Adjustments expenditures to decrease by \$0.4 million compared to the 2018-2022 \$1.1 million five-year average.<sup>94</sup>

### **Leak Detection And Repair (LDAR) Notice of Proposed Rulemaking (NPRM)**

Mr. Abona states that PHMSA (Pipeline and Hazardous Materials Safety Administration) released its Notice of Proposed Rulemaking (NPRM) on Leak Detection and Repair (LDAR) on May 18, 2023.<sup>95</sup> He adds that the LDAR Final Rule is expected to be published by PHMSA in the third quarter of 2024, and with the effective date of the rule is currently six months from the final rule publication and with the rule being published on September 1, 2024, the effective date would be March 1, 2025.<sup>96</sup> Mr. Abona states

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<sup>90</sup> 3 Tr 360.

<sup>91</sup> Id.; Ex. A-12, Sch. B5.1.

<sup>92</sup> 3 Tr 361.

<sup>93</sup> 3 Tr 363; Ex. A-12, Sch. B5.1.

<sup>94</sup> Id.

<sup>95</sup> 3 Tr 363.

<sup>96</sup> 3 Tr 364.

that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$15.0 million of LDAR capital expenditures.<sup>97</sup>

The Attorney General and Staff take issue with DTE's request for LDAR capital expenditures. Mr. Coppola states that the forecasted expenditures are premature and not likely to occur in the amounts forecasted in the projected test year.<sup>98</sup> He adds that DTE has not presented a detailed plan of how it plans to implement the new rule requirements and over what timeframe, the equipment needed over that timeframe, and how the new requirements dovetail DTE's current practices and procedures in detecting and repairing gas leaks.<sup>99</sup> He states that based on information provided in discovery responses, DTE had nearly \$4.0 million of capital expenditures in 2023 related to leak detection and repairs, and that DTE is proposing to spend in excess of \$53 million on leak detection and repairs for the projected test year.<sup>100</sup> He asserts that it is not clear why, in less than one year, the total spending would more than double or whether DTE would have the capability to accomplish that level of increased activity and related spending.<sup>101</sup> Thus, he recommends that the Commission reject the \$14,970,000 of capital expenditures and the \$10,276,000 of O&M expense forecasted by DTE for the projected test year.<sup>102</sup>

Ms. Creisher states that absent the final published regulations related to LDAR, Staff does not support including capital expenditures and O&M expenses as proposed by DTE.<sup>103</sup> She adds that Staff recommends that the LDAR capital expenditures, excluding

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<sup>97</sup> 3 Tr 364-365, Table 9; Ex. A-12, Sch. B5.1.

<sup>98</sup> 4 Tr 1447.

<sup>99</sup> Id.

<sup>100</sup> Id.

<sup>101</sup> 4 Tr 1447-1448.

<sup>102</sup> 4 Tr 1448.

<sup>103</sup> 4 Tr 1792.

\$6,000,000 for the purchase of additional Picarro vehicle-based leak detection systems as defined in DTE's discovery response (Staff Exhibit S-10.3), in the amount of \$8,970,000 should not be recovered until such a time that the final rule is published and the actual effective date is known.<sup>104</sup> She adds that Staff recommends that LDAR O&M expenses in the amount of \$10,276,000 should also not be recovered in base rates at this time.<sup>105</sup> She states that Staff is supportive of DTE's use of a regulatory deferral mechanism accounting treatment for O&M expenses necessary for compliance with regulatory requirements until DTE's next rate case proceeding.<sup>106</sup>

Mr. Abona counters that he does "not entirely" agree with Mr. Coppola's recommended disallowance.<sup>107</sup> He adds that DTE recognizes the validity of some points raised by Mr. Coppola, he argues that the \$6 million of expenditures for the procurement of Picarro units is fully justified.<sup>108</sup> He asserts that the Picarro units procurement is "proactive, undertaken in response to the upcoming PHMSA LDAR regulation", and is a "strategic move to comply with expected regulatory changes" and to adhere to the "anticipated LDAR mandates."<sup>109</sup>

This PFD agrees with the Attorney General and Staff that DTE's proposed capital expenditures are premature and should not be recovered until such a time that the final LDAR rule is published and the actual effective date is known. This PFD disagrees with DTE and Staff that the \$6 million expenditure to procure the Picarro units should

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<sup>104</sup> 4 Tr 1792-1793; Ex. S-10.3.

<sup>105</sup> 4 Tr 1793.

<sup>106</sup> Id.

<sup>107</sup> 3 Tr 390.

<sup>108</sup> Id.

<sup>109</sup> 3 Tr 390-391.

nonetheless be allowed. Neither DTE nor Staff offer any reason why this expenditure should be treated differently from the other LDAR capital expenditures; that is, why the Picaaro expenditures to be made in anticipation of future LDAR mandates should be allowed while other LDAR expenditures similarly to made in anticipation of the same LDAR mandates are not. Thus, this PFD recommends that the Attorney General's proposed disallowance of \$14,970,000 of capital expenditures and the \$10,276,000 of O&M expense forecasted by DTE for the projected test year be accepted.

Mr. Fitzhenry notes that DTE proposes an upward adjustment of \$30.5 million in O&M expense related to inflation, using labor inflation rates of 3.2% for 2023, 2.9% for 2024, and 2.9% for 2025.<sup>110</sup> He asserts that DTE supports the wage inflation factor by relying on historical practices for the non-represented workforce and existing collective bargaining agreements for represented employees.<sup>111</sup> He states that absence any direct evidence demonstrating increased company labor cost, the 3.0% wage inflation rate should not be relied on to escalate O&M expense.<sup>112</sup>

Mr. Fitzhenry states that DTE uses the CPI-U (Consumer Price Index for Urban Customers) to determine the appropriate non-labor inflation rate, with DTE's proposed non-labor inflation rate being 4.1% for 2023, 2.9% for 2024, and 2.2% for 2025.<sup>113</sup> He asserts that the Blue Chip Economic Indicators industry expert consensus GDP Chained Price Index is better used, with the Blue GDP Chained Price Index being 2.6% for 2023,

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<sup>110</sup> 4 Tr 1322-1323. Citation omitted.

<sup>111</sup> 4 Tr 1323. Citation omitted.

<sup>112</sup> Id.

<sup>113</sup> 4 Tr 1324; Ex. A-13, Sch. C12.

2.2% for 2024, and 2.2% for 2025.<sup>114</sup> Thus, he recommends that DTE use the Blue Chip GDP Chained Price Index for the O&M inflation factors, which adjustment to the inflation factor reduced DTE's proposed O&M expense by approximately \$6.9 million.<sup>115</sup>

Mr. Abona states that from January 1, 2023, through September 30, 2025, DTE will have incurred \$71.6 million of public improvement capital expenditures.<sup>116</sup> He adds that on average, DTE Gas expects its 2023-2025 routine public improvement expenditures to be \$3.4 million higher than the 2018-2022 \$22.1 million five-year average capital spend level driven mainly by the East Jefferson and Connor & I-94 6 projects.<sup>117</sup>

Mr. Abona states the East Jefferson project entails the installation of approximately 12.5 miles of new plastic main, installation of four new regulator stations, retesting of 1.5 miles of existing plastic main, abandonment of approximately 9.2 miles of cast iron and unprotected steel main, together with the replacement of 394 service lines and the moving out of 102 associated inside meters.<sup>118</sup> He adds that DTE Gas is placing the East Jefferson public improvement project into service in phases over a two-year period between May 2022 and December 2024, and that main replacement work will continue in 2024 as part of the Gas Renewal Program.<sup>119</sup> He states that from December 31, 2022, the end of the historical test year, through September 30, 2025, the end of the projected test year, DTE will have incurred \$8.1 million of East Jefferson project capital expenditures.<sup>120</sup>

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<sup>114</sup> Id.

<sup>115</sup> 4 Tr 1324-1325, Table CTF-6.

<sup>116</sup> Id.; Ex. A-12, Sch. B5.1, p. 2.

<sup>117</sup> 3 Tr 336; Ex. A-12, Sch. B5.5.

<sup>118</sup> Id.

<sup>119</sup> 3 Tr 338.

<sup>120</sup> 3 Tr 339.

Mr. Abona states that the Connor and I-94 project is a relocation of the 24" Steel main from under I-94 due to conflict with the MDOT I-94 modernization project.<sup>121</sup> He adds that from 2023 through September 2025, DTE will have incurred capital expenditures totaling \$6.98 million, which is the total estimated capital expenditures for the Connor and I-94 project.<sup>122</sup>

Mr. Coppola states that based on the information provided by DTE, he determined that the three-year average routine capital spending in this area was \$16,247,000, which amount he arrived at by removing four major projects from the historical periods (2021-2023), including the East Jefferson and the Connor/I-94 project costs.<sup>123</sup> He adds that after adjusting for inflation, he calculated forecasted capital expenditures of \$12,502,000 for the 9 months ending September 2024 and \$16,944,000 for the projected test year.<sup>124</sup>

Mr. Coppola states that to determine the routine level of capital expenditures in this spending category, he removed two large projects identified by DTE: Conner/I-94 and the Springfield/I-94, which total to \$8,373,000 for 2024 and \$6,280,000 for the 9 months ending September 2024.<sup>125</sup> He adds that by removing this amount from DTE's total forecasted amount of \$19,942,000, he determined routine capital expenditures for public improvements in DTE's forecast for the 9 months ending September 2024 to be \$13,662,000.<sup>126</sup> He states that for 2025, DTE forecasted \$19,459,000 in capital expenditures, but did not identify any projects supporting that amount.<sup>127</sup>

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<sup>121</sup> 3 Tr 341.

<sup>122</sup> Id.

<sup>123</sup> 4 Tr 1439. Citation omitted.

<sup>124</sup> Id.

<sup>125</sup> 4 Tr 1439-1440.

<sup>126</sup> 4 Tr 1440.

<sup>127</sup> Id.

Mr. Coppola states that in comparing my calculations of the forecasted capital expenditures for the 9 months ending September 2024 of \$12,502,000 to DTE's adjusted forecasted amount of \$13,372,000, he find that DTE's forecast is overstated by \$1,160,000, and that for the projected test year, DTE's forecasted amount of \$19,518,000 is excessive in comparison to his forecast of \$16,944,000 by \$2,574,000.<sup>128</sup> He asserts that DTE did not provide any justification for the higher capital expenditures, and thus, he recommends that the Commission remove \$1,160,000 for the 9 months ending September 2024 and \$2,574,000 from the capital expenditures forecasted by DTE for public improvements.<sup>129</sup>

Mr. Abona counters that excluding the four largest projects when estimating future capital expenditures is a flawed methodology because it disregards significant projects that could dramatically affect the average capital expenditures, and that by omitting them, the estimation fails to capture the full spectrum of costs DTE faces, leading to an average that does not accurately reflect the true variability and upper limits of costs.<sup>130</sup> He adds that it is important to recognize that these extensive projects are not merely isolated to a single year; rather, they are ongoing endeavors that will recur over time and ought to be factored in when forecasting capital expenditures.<sup>131</sup>

This PFD agrees with DTE, noting that Mr. Coppola does not provide a reasonable explanation for excluding major projects from test year cost projections. Thus, this PFD recommends that the Attorney General's proposed disallowance be rejected.

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<sup>128</sup> Id.

<sup>129</sup> Id.

<sup>130</sup> 3 Tr 385-386.

<sup>131</sup> 3 Tr 386.

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$17.6 million of service abandonment capital expenditures.<sup>132</sup> He adds that on average, DTE expects its 2023-2025 routine service abandonment expenditures to be relatively flat compared to the 2018-2022 \$6.4 million five-year average.<sup>133</sup>

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$71.5 million of service alteration capital expenditures.<sup>134</sup> He adds that on average, DTE Gas expects its 2023-2025 service alteration expenditures to be \$5.7 million higher per year than the 2018-2022 \$20.2 million five-year average.<sup>135</sup>

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$32.5 million of service renewal capital expenditures.<sup>136</sup> He adds that on average, DTE Gas expects its 2023-2025 routine service renewal expenditures to be \$0.97 million lower per year than the 2018-2022 \$12.8 million five-year average.<sup>137</sup>

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$101.8 million of system reliability capital expenditures.<sup>138</sup> He adds that on average, DTE Gas expects its 2023-2025 planned routine system reliability expenditures to be \$10.4 million higher per year than the 2018-

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<sup>132</sup> 3 Tr 342.

<sup>133</sup> Id., Table 3.

<sup>134</sup> 3 Tr 343; Ex. A-12, sch. B5.1.

<sup>135</sup> Id.

<sup>136</sup> 3 Tr 345.

<sup>137</sup> Id.

<sup>138</sup> 3 Tr 346; Ex. A-12, Sch. B5.1.

2022 \$26.4 million five-year average, with the amount above the five-year average being driven by the Northeast Belt Pipe Replacement project.<sup>139</sup> He states that cost per unit increases are driven by many factors including general inflationary increases and by specific enhancements to projects that include replacement of regulator stations.<sup>140</sup>

Mr. Coppola states that DTE's discovery response shows that in 2023 DTE actually installed only 87 units instead of the forecasted 97 units planned and at a higher unit cost.<sup>141</sup> He adds that from the actual units completed between 2021 and 2023, he calculated an average of 86 units completed annually, noting that in comparison, the 118 units forecasted by DTE for 2024 is an increase of 37% over the three-year average, and that for 2025, the 103 units forecast is an increase of 20% over the three-year average.<sup>142</sup> He asserts that DTE has not provided any justification to support the higher number of forecasted units or projects.<sup>143</sup> He adds that in response to discovery, DTE stated that several of the listed projects are in the planning or early design phase, indicating that the projects have not yet been sufficiently developed through the engineering phase to be certain for completion within the 2025 projected test year.<sup>144</sup>

Mr. Coppola states that based on the information provided by DTE, he calculated the reduction in forecasted capital expenditures in this spending category using the 86 units completed on average annually over the most recent three years versus the number of units forecasted by DTE.<sup>145</sup> He adds that he calculated lower capital expenditures of

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<sup>139</sup> 3 Tr 347.

<sup>140</sup> 3 Tr 347-349, Table 6.

<sup>141</sup> 4 Tr 1441; ex. AG-6.

<sup>142</sup> Id.

<sup>143</sup> Id.

<sup>144</sup> 4 Tr 1441-1442; Ex. AG-6.

<sup>145</sup> 4 Tr 1442.

\$9,359,000 for 2024 and \$7,019,000 for the 9 months ending September 2024. Similarly, for 2025, he states that DTE's forecasted unit cost of \$332,039 results in lower capital expenditures of \$5,645,000, and for the 12 months ending September 2025, the applicable adjustment is a reduction of \$6,573,000.<sup>146</sup> Thus, he recommends that the Commission remove the \$7,019,000 from DTE's forecasted capital expenditures for the 9 months ending September 2024 and \$6,573,000 for the 12 months ending September 2025.<sup>147</sup>

Mr. Abona counters that the proposed unit figures for 2024 and 2025 are higher than the historical average from 2021 to 2023 for several reasons, including that the completion rate of System Reliability projects experienced a notable decline in the years 2020, 2021, and 2022 due to the COVID pandemic's disruption of onsite construction activities and interruptions in the global supply chain, while noting that in 2024 and 2025, the material shortages that previously affected project completions have largely been resolved.<sup>148</sup> He adds that DTE is seeing an increased rate of regulator stations that need to be replaced, an increase in overpressure events associated with regulator stations in recent years, and that DTE will be increasing the number of compliance projects to remediate above grade district regulators to complete the remaining 755 district regulators by 2035 to meet the commitment to the Commission.<sup>149</sup>

This PFD agrees with the Attorney General. While DTE offers some reasons in support of its projections, DTE fails to rebut the Attorney General's assertion that several of the listed projects are in the planning or early design phase and thus have not yet been

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<sup>146</sup> Id.

<sup>147</sup> Id.

<sup>148</sup> 3 Tr 387.

<sup>149</sup> Id.

sufficiently developed through the engineering phase to be certain for completion within the 2025 projected test year. Thus, this PFD recommends that Mr. Coppola's proposed disallowance of \$7,019,000 from DTE's forecasted capital expenditures for the 9 months ending September 2024 and \$6,573,000 for the 12 months ending September 2025 be accepted.

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$56.6 million of Communications & Control – 3 Meters capital expenditures.<sup>150</sup> He adds that on average, DTE expects its 2023-2025 Communications & Control – Meters expenditures to be \$5.6 million higher per year than the 2018-2022 \$14.8 million five-year average.<sup>151</sup>

Mr. Coppola states that the information provided by DTE in discovery shows that although average meter prices increased from 2018 to 2022 peaking at \$220 in 2022, and in 2023 the average price decreased to \$167.<sup>152</sup> In contrast, the Company forecasted average meter prices of \$215 for 2024 and \$190 for 2025. The forecasted prices represent increases of 29% and 14%, respectively, over the 2023 actual price of \$167. He adds that in contrast, the Company forecasted average meter prices of \$215 for 2024 and \$190 for 2025, which forecasted prices represent increases of 29% and 14%, respectively, over the 2023 actual price of \$167.<sup>153</sup>

Mr. Coppola states that for modules, average prices reached a peak of \$57 in 2023 and DTE forecasted further increases to \$68 in 2024 and \$71 in 2025, which forecasted prices represent increases of 19% and 25%, respectively, over the 2023 actual price of

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<sup>150</sup> 3 Tr 355; Ex. A-12, Sch. B5.1.

<sup>151</sup> Id.

<sup>152</sup> 4 Tr 1443.

<sup>153</sup> Id.; Ex. AG-7.

\$57.<sup>154</sup> He asserts that there is no quantifiable evidence that historical price increases will continue into the future and particularly at the rate of increases he identified.<sup>155</sup> He states that by applying the forecasted rate of inflation for 2024 and 2025 to the actual price paid per meter in 2023 of \$167, he calculated a forecasted price per meter of \$171 for 2024 and \$175 for 2025, and that using these prices and the number of units forecasted by DTE for 2024 and 2025, he calculated forecasted capital expenditures of \$6,605,000 and \$8,760,000, respectively for each year, which amounts are \$1,719,000 lower than the \$8,324,000 for 2024 and \$763,000 lower from the \$9,523,000 for 2025 shown in DTE's discovery response.<sup>156</sup>

Mr. Coppola states that for the module purchases, he applied the inflation factors for 2024 and 2025 to the actual price of \$57 for 2023 to arrive at the forecasted prices of \$58 and \$59 for each year, and that applying these prices to the number of units forecasted by DTE for 2024 and for 2025, he calculated forecasted capital expenditures of \$5,130,000 and \$3,995,000 for each respective year, which amounts are lower by \$898,000 from the \$6,028,000 forecasted by DTE for 2024 and \$816,000 from the \$4,811,000 forecasted by DTE for 2025.<sup>157</sup>

Mr. Coppola states that the total lower forecasted amounts for meters and modules, combined, for 2024 and 2025 are \$2,617,000 and \$1,579,000, respectively.<sup>158</sup> Thus, Mr. Coppola recommend that the Commission remove capital expenditures of

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<sup>154</sup> Id.

<sup>155</sup> 4 Tr 1444.

<sup>156</sup> Id.; Ex. AG-7.

<sup>157</sup> Id.

<sup>158</sup> 4 Tr 1445.

\$1,963,000 for the 9 months ending September 2024 and \$1,406,000 for the 12 months ending September 2025.<sup>159</sup>

Mr. Abona counters that the inflation adjustment factor used by Mr. Coppola currently is approximately 2.4%, which does not align with the actual cost increases DTE is experiencing, noting that three primary vendors from which DTE sources gas meters and modules have raised their prices, on average, by 8% from 2023 to 2024 and that the price of DTE's largest and most expensive rotary meters, utilized in commercial and industrial settings, has increased by 12.5%.<sup>160</sup> He adds that the historic average meter prices cannot be used to estimate the average meter price for future years, as the mix and volume of meters and modules procured each year differ which results in fluctuating average meter costs year over year.<sup>161</sup>

This PFD finds that DTE has supported its cost projections for the meters and modules. Thus, this PFD recommends that the Commission reject the Attorney General's recommended disallowance.

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$2.1 million of Permits and Other Adjustments capital expenditures.<sup>162</sup> He adds that on average, DTE expects its 2023-2025 planned routine Permits and Other Adjustments expenditures to decrease by \$0.4 million compared to the 2018-2022 \$1.1 million five-year average.<sup>163</sup>

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<sup>159</sup> 4 Tr 1445.

<sup>160</sup> 3 Tr 388, citing Ex. A-30 (Confidential).

<sup>161</sup> Id.

<sup>162</sup> 3 Tr 363; Ex. A-12, Sch. B5.1.

<sup>163</sup> Id.

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$39.6 million of routine transmission plant capital expenditures.<sup>164</sup> He adds that on average, DTE expects its 2023-2025 routine transmission plant expenditures to be \$3.0 million higher per year than the 2018-2022 \$11.5 million five-year average.<sup>165</sup>

Mr. Coppola states that DTE was asked to identify the current phase of development for four large projects forecasted for 2025, with the projects with related 2025 capital expenditures being: the MLV7 Replacement (\$2,800,000), the Au Gres Tributary Pipe Replacement (\$2,350,000), the Willow Gate Station (\$2,000,000), and the MLV 5C Line Replacement (\$1,928,000).<sup>166</sup> He adds that the total forecasted cost for the four projects is \$9,078,000 for 2025 and \$6,809,000 for the projected test year.<sup>167</sup> He asserts that DTE evaded answering the question about the current phase of development, instead stated that engineering and construction phases would occur sometime in 2024 and 2025.<sup>168</sup> He asserts that the evasive answer indicates that the four projects are currently in the initial conceptual or planning phase with no stated start and completion date for project engineering.<sup>169</sup> As such, he argues that these projects are still in the early phase of development with no assured timeline and thus premature to include in rate base in this rate case.<sup>170</sup> Thus, he recommends that the Commission disallow \$6,809,000 of capital expenditures for the projected test year.<sup>171</sup>

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<sup>164</sup> 3 Tr 367; Ex. A-12, Sch. B5.1.

<sup>165</sup> Id.

<sup>166</sup> 4 Tr 1462.

<sup>167</sup> Id. Citation omitted.

<sup>168</sup> Id.; Ex. AG-14.

<sup>169</sup> Id.

<sup>170</sup> Id.

<sup>171</sup> Id.

Mr. Abona counters that DTE Gas is utilizing a two-year project cycle for routine projects with engineering to be complete in year 1 and construction in year 2.<sup>172</sup> He adds that therefore, the plan for the four (4) routine projects mentioned by Mr. Coppola will be to perform the engineering in 2024 and the construction during the 2025 construction season.<sup>173</sup>

Noting that DTE's explanation of the two-year project cycle is included in its discovery response, albeit somewhat cursorily stated, this PFD agrees with DTE and finds that these expenditures are adequately supported. Thus, this PFD recommends that the Commission reject the Attorney General's proposed disallowance.

Mr. Abona states from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$56.6 million of routine storage plant capital expenditures.<sup>174</sup> He adds that on average, DTE expects its 2023-2025 routine storage plant expenditures to be \$0.8 million lower than the 2018-2022 \$21.0 million five-year average.<sup>175</sup>

Mr. Coppola states that DTE provided the work units for each program from 2018 to 2025, with the forecasted number of work units for 2024 and 2025 being generally lower for those years than the previous three years from 2021 to 2023, and for gas storage, DTE forecasted 44 work units for 2024 and 37 for 2025.<sup>176</sup> He adds that in comparison, DTE completed 63 work units on average annually during 2021- 2023.<sup>177</sup> He states that for the storage compression program, DTE forecasted 78 units for 2024 and

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<sup>172</sup> 3 Tr 391.

<sup>173</sup> Id.

<sup>174</sup> 3 Tr 370: Ex. A-12, Sch. B5.1.

<sup>175</sup> 3 Tr 371.

<sup>176</sup> 4 Tr 1468.

<sup>177</sup> Id.

60 units for 2025, while on average over the 2021-2023 period, DTE completed 110 units.<sup>178</sup>

Mr. Coppola states he calculated the historical average cost per work unit for the 2021-2023 period at \$54,642, and after applying the inflation factor, he calculated a unit cost of \$58,980 for 2024, which resulted in a forecasted cost of \$2,467,000 for the year, or \$1,850,000 for the 9 months ending September 2024.<sup>179</sup> He adds that in comparison, DTE forecasted capital expenditures of \$3,108,000 for the 9-month period, such that DTE's forecast is overstated by \$1,258,000.<sup>180</sup>

Mr. Coppola states that he calculated forecasted capital expenditures of \$2,120,000 for 2025 and \$2,207,000 for the 12 months ending September 2025, noting in comparison, DTE forecasted capital expenditures of \$4,067,000 for the 12-month period.<sup>181</sup> He concludes that DTE's forecast is overstated by \$1,860,000.<sup>182</sup>

Mr. Coppola states that for the storage compression program, he calculated a unit cost of \$136,265 for 2024, which resulted in a forecasted cost of \$10,629,000 for the year, or \$7,972,000 for the 9 months ending September 2024.<sup>183</sup> He adds that in comparison, DTE forecasted capital expenditures of \$16,220,000 for the 9-month period, such that he asserts DTE's forecast is overstated by \$8,248,000.<sup>184</sup>

Mr. Coppola concludes that in total, for the gas storage and compression programs, DTE's forecasted capital expenditures are overstated by \$9,506,000 for the 9

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<sup>178</sup> Id.

<sup>179</sup> 4 Tr 1469.

<sup>180</sup> Id.

<sup>181</sup> Id. Citation omitted.

<sup>182</sup> Id.

<sup>183</sup> 4 Tr 1469-1470. Citation omitted.

<sup>184</sup>

months ending September 2024 and \$3,819,000 for the 12 months ending September 2025.<sup>185</sup> He asserts that DTE's forecasted capital expenditures in this spending category are not reasonable and DTE has not adequately justified the higher forecasted costs in comparison to recent historical unit cost plus forecasted inflation.<sup>186</sup> Thus, he recommends that the Commission remove the excess capital expenditures of \$9,506,000 for the 9 months ending September 2024 and the \$3,819,000 for the 12 months ending September 2025.<sup>187</sup>

Mr. Abona counters that using the average cost per unit from 2021 to 2023 does not reflect the rigor and corresponding cost of planned projects (units) for 2024 and 2025.<sup>188</sup> He adds that the cost per unit varies based on project scope and complexity of associated construction activities, with the increased complexity and costs for construction resources result in a higher cost per unit.<sup>189</sup> He states that several compressor units installed as part of the 2017-2018 NEXUS expansion are projected to surpass the cumulative run hour threshold recommended by original equipment manufacturer (OEM), requiring an engine replacement with turbine engine replacements totaling \$3.5 - \$4.0 million dollars/unit.<sup>190</sup>

This PFD finds that DTE's explanation in support of these projected expenditures is lacking any specificity backing up its general statements that the associated construction activities are complex. Moreover, while referencing a specific cost for a turbine engine replacement, which it asserts are projected to occur based on the

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<sup>185</sup> 4 Tr 1470.

<sup>186</sup> Id.

<sup>187</sup> Id.

<sup>188</sup> 3 Tr 392.

<sup>189</sup> Id.

<sup>190</sup> 3 Tr 393.

equipment surpassing the recommended cumulative hour threshold, DTE does not provide any estimate of the number of such replacements to occur even though such an estimate should be easy to compile from objective criteria (the number of turbines projected to exceed the run hour threshold). Thus, this PFD agrees that DTE's projections are not adequately supported and thus recommends that the Commission adopt the Attorney General's recommended disallowance of \$9,506,000 for the 9 months ending September 2024 and the \$3,819,000 for the 12 months ending September 2025.

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$43.2 million of transportation vehicles and equipment capital expenditures.<sup>191</sup> He adds that on average, DTE expects its 2023-2025 routine transportation vehicles and equipment expenditures to be \$5.3 million higher per year than the 2018-2022 \$10.4 million five-year average.<sup>192</sup> He states that the higher expenditures per year will fund replacements for vehicles that are beyond the lifecycle typical for such assets and are in poor condition.<sup>193</sup> He adds that vehicles and equipment are more expensive compared to historical averages due to inflation and supply chain constraints.<sup>194</sup> He asserts, as an example, a 2023 model year cargo van is approximately \$8,300 more than a 2019 model year cargo van.<sup>195</sup>

Mr. Coppola states that information provided by DTE shows forecasted 2024 vehicle and equipment purchase costs with a cost per vehicle of \$136,783 and 2025 forecasted purchases with a cost per vehicle of \$126,145.<sup>196</sup> He adds that in contrast,

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<sup>191</sup> 3 Tr 376.

<sup>192</sup> 3 Tr 377.

<sup>193</sup> Id.

<sup>194</sup> Id.

<sup>195</sup> Id.

<sup>196</sup> 4 Tr 1471.

DTE spent \$79,010 per vehicle in 2023 and for the three year 2021-2023 the average purchase cost per vehicle was \$80,439.46.<sup>197</sup> He states that the forecasted cost per vehicle in 2024 is 70% above the three-year average cost and the 2025 forecasted unit cost is 57% over the same average cost.<sup>198</sup> He asserts that the forecasted cost per vehicle for 2024 and 2025 is significantly inflated and overstated.<sup>199</sup>

Mr. Coppola states that he determined that for the 47 vehicles and equipment that DTE plans to purchase in 2024 the forecasted cost is \$3,879,000 and \$2,909,000 for the 9 months ending September 2024, while noting that in comparison, DTE forecasted capital expenditures for the 9-month period of \$10,006,000.<sup>200</sup> He concludes that DTE's forecast is overstated by \$7,097,000.<sup>201</sup> He states that he determined the total forecasted cost for 2025 at \$10,543,000, while for the 12 months ending September 2025, the forecasted cost is \$8,877,000.48.<sup>202</sup> He notes that in comparison, DTE forecasted capital expenditures of \$20,255,000 and concludes that DTE's forecast is overstated by \$11,378,000.<sup>203</sup>

Mr. Coppola asserts that DTE did not provide any evidence to justify the large unit cost increase of 57% to 70% over recent historical levels, and thus that DTE's forecast is not reasonable and is not adequately supported.<sup>204</sup> Thus, he recommends that the Commission remove the excess capital expenditures of \$7,097,000 for the 9 months ending September 2024 and \$11,378,000 for the projected test year.<sup>205</sup>

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<sup>197</sup> Id.; Ex. AG-18.

<sup>198</sup> Id.

<sup>199</sup> Id.

<sup>200</sup> 4 Tr 1472.

<sup>201</sup> Id.

<sup>202</sup> Id.

<sup>203</sup> Id.

<sup>204</sup> Id.

<sup>205</sup> Id.

Mr. Abona counters that in 2024 and 2025, the average cost per vehicle is projected to rise due to the acquisition of a different mix of vehicles, with the fleet's most sophisticated and costly units, the Class 7 and 8 trucks, contributing significantly to this increase.<sup>206</sup> He adds that while no such trucks were added to the company's inventory in 2021, and only two were acquired in each of the years 2022 and 2023, DTE plans to purchase 13 trucks in 2024 and 15 in 2025, which accounts for the majority of the anticipated surge in the average vehicle cost during these years.<sup>207</sup> He notes that DTE provided a list of vehicles replaced, list outlined both the financial and quantitative data for each vehicle class from 2018 to 2025.<sup>208</sup>

This PFD finds that DTE has adequately supported its projected expenditures for this category, and thus recommends that the Commission reject the Attorney General's proposed disallowance.

### **Gas Information Technology (IT) Spending**

Ms. Fedele states that from December 31, 2022, the end of the historical test year, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$33.1 million of Gas Information Technology capital expenditures.<sup>209</sup> DTE asserts that its IT investment spending is part of the DTE IT Five-year Plan for 2021-2025, which was filed on March 22, 2021, in Case No. U-20561.<sup>210</sup>

Mr. Busby states that DTE's Annual Planning Cycle (APC) is how DTE refines its investment strategies, establishes financial targets, and sanctions work for IT

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<sup>206</sup> 3 Tr 394.

<sup>207</sup> Id.

<sup>208</sup> 3 Tr 395; Ex. A-30, Sch. T5.

<sup>209</sup> 4 Tr 1903: ex. A-12, sch. B5.

<sup>210</sup> DTE initial brief, p. 29.

investments.<sup>211</sup> He adds that the business units come together annually to review, prioritize, and authorize the next two years of IT investments, aligned with the assigned capital targets.<sup>212</sup> He states that this process is detailed in the DTE Five-Year IT Plan 2021-2025 filed in Docket No. U-20642.<sup>213</sup> He states that DTE is requesting capital expenditures in the amount of \$15.0 million for the historical test year ended December 31, 2022, \$18.2 million in the bridge period (21 months ending September 30, 2024), and \$10.2 million for the projected test period ending September 30, 2025.<sup>214</sup>

Ms. Danielle Rogers states that Staff is recommending a 20% disallowance for IT projects with Level 2 cost estimates, which equates to a disallowance of \$0.63 million in the 9 months ending 9/30/2024 and \$1.13 million in the test year ending 9/30/2025 in capital, as well as \$0.12 million in O&M.<sup>215</sup> She adds that the IT projects included in this disallowance are Gas Application Health, Clicksoft Enhancements, Gas Enhancements, Gas Construction- As Building, Gas Construction- Contractor Inspection, and SEMI Picarro Survey Unit Renewal.<sup>216</sup> She states that Staff recommends this disallowance for these projects because of their incomplete, indefinite, and imprecise nature.<sup>217</sup> Noting that projects are given a Level 2 cost estimate over a year before implementation, she asserts that these projects have not completed the review process, do not have formal final approval, and have not received allocation in the internal budget.<sup>218</sup> She adds that

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<sup>211</sup> 4 Tr 2088.

<sup>212</sup> Id.

<sup>213</sup> Id.

<sup>214</sup> 4 Tr 2082; ex. A-12, Sch. B5.4.

<sup>215</sup> 4 Tr 1601; Ex. S-13.2.

<sup>216</sup> Id.

<sup>217</sup> Id.

<sup>218</sup> Id.

projects with Level 2 cost estimates are not yet under contract, and argues that many things can change in the year(s) prior to execution such as a change in project scope, the necessity of the project, prioritization within the Annual Planning Cycle (APC), and vendor availability or cost.<sup>219</sup> She asserts that this can lead to the project being delayed or not implemented at all, and that it is unfair to pass their total costs onto ratepayers at this time.<sup>220</sup>

Ms. Rogers states that Staff decided on a 20% recommended adjustment for Level 2 projects using the Association for the Advancement of Cost Engineering (AACE) International Recommended Practice Cost Estimation Classification, the information provided in DTE's two previous electric rate cases, Case Nos. U-20836 and U-21297 for the basis of Level 2 cost estimations, and actions in the Annual Planning Cycle (APC) to determine a class of estimate.<sup>221</sup> Noting that DTE has not testified to any changes in cost estimation practices in the instant case, and that as indicated by DTE in Case Number U-20836, she states that Level 2 cost estimates are based on labor hours, hardware costs, and software costs, but do not have a defined scope.<sup>222</sup> She asserts that Staff determined this level of cost information best coincides with the AACE Class III estimate, with semi-detailed unit costs and an accuracy range of +30%/-20%.<sup>223</sup> She adds that if DTE spends more than 80% of the requested expense, it can seek recovery in the next electric rate

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<sup>219</sup> 4 Tr 1601-1602.

<sup>220</sup> 4 Tr 1602.

<sup>221</sup> Id.

<sup>222</sup> Id.

<sup>223</sup> Id.

case by providing evidence to be reviewed for reasonableness and prudence.<sup>224</sup> She notes that the Commission approved a 20% disallowance of costs related to IT projects with Level 2 cost estimates in DTE's two previous electric rate cases, Case Nos. U-20836 and U-21297, with the Commission stating in part:

“Regardless of whether costs are for projects that are similar to earlier projects, it is still necessary to have a clear understanding of the timing of the project and a level of detail regarding the costs that demonstrates that the costs are reasonable and prudent—without that, the costs cannot be properly evaluated by the Commission for inclusion in rate base and the projections are incomplete.”<sup>225</sup>

Ms. Rogers also notes that in Case Number U-21297, the Commission stated in part, “The Commission also finds persuasive the Staff’s rationale for using the AACE Class 3 Estimate to derive its 20% disallowance here.”<sup>226</sup>

Ms. Rogers states that the IT Shared Asset Charge is the cost that DTE Gas pays to DTE Electric Company for their use of the IT programs/software/equipment, owned by DTE Electric, that benefits both DTE Gas and DTE Electric Companies.<sup>227</sup> Noting that DTE is projecting an IT shared asset charge of \$38.6 million, she asserts that Staff recommends a \$1.9 million adjustment to the IT shared asset charge so that the cost DTE Gas Company is paying DTE Electric Company for the use of the jointly beneficial IT programs/software/equipment matches the revenue that DTE Electric Company has been approved to collect per the Commission’s order in U-21297.<sup>228</sup> She adds that if DTE Gas paid the amount projected in the instant case, \$38.6 million, DTE Electric Company will gain an extra \$1.9 million that is unaccounted for, which represents an unnecessary

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<sup>224</sup> 4 Tr 1603.

<sup>225</sup> Id. Citation omitted.

<sup>226</sup> 4 Tr 1604. Citation omitted.

<sup>227</sup> Id.

<sup>228</sup> 4 Tr 1605, 1606; Ex. S-13.4.

burden to DTE Gas ratepayers.<sup>229</sup> She notes that in response to discovery from the Attorney General, DTE admits the reason for the discrepancy, states the shared asset charge should be lowered by \$1.9 million, and updated Ex. A-13, Sch. C5.6 to reflect the change.<sup>230</sup>

DTE counters that Ms. Rogers' claim that Level 2 cost estimates are obtained prior to a comprehensive review is simply incorrect, asserting that the IT business case costs are estimated as part of the rigorous APC process.<sup>231</sup> DTE asserts that Ms. Rogers' -20% variance recommendation fails to consider that DTE has already informed its Level 2 estimate using the same guidelines that Ms. Rogers supports, with DTE's estimation process utilizing guidelines from AACE as well as the American National Standards Institute (ANSI).<sup>232</sup> DTE asserts that Ms. Rogers' selection and recommendation of the lowest accuracy range provided for Class 3 estimates fails to consider that the AACE Class 3 estimates also provide an upper range of +30%.<sup>233</sup> DTE argues that it is more accurate to compare DTE Gas's Level 2 estimates to AACE Class 2 estimates with respect to the level of project definition and deliverables defined and estimated in DTE's business cases.<sup>234</sup>

This PFD agrees with Staff that the recommended disallowance should be made. Staff's approach in determining the disallowance is consistent with those previously approved by the Commission. Moreover, DTE has not effectively rebutted Staff's assertions in support of the disallowance. Thus, this PFD recommends that the

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<sup>229</sup> 4 Tr 1606.

<sup>230</sup> Id.; Ex. S-13.6.

<sup>231</sup> DTE initial brief, p. 30.

<sup>232</sup> Id., p. 31.

<sup>233</sup> Id.

<sup>234</sup> Id. Citation omitted.

Commission accept Staff's 20% disallowance for IT projects with Level 2 cost estimates, which equates to a disallowance of \$0.63 million in the 9 months ending 9/30/2024 and \$1.13 million in the test year ending 9/30/2025 in capital.

Mr. Abona states that the Gas Scheduling Optimizer tool is a computer program that leverages an advanced scheduling algorithm that uses real-time and historical data to optimize schedules to enable crews to successfully complete more jobs each week and dynamically adjust for contingencies.<sup>235</sup> He states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$4.1 million of Gas Scheduling Optimizer project capital expenditures.<sup>236</sup> He adds that the total direct capital investment for the Gas Scheduling Optimizer, from its inception from January 1, 2022, through December 31, 2023, is approximately \$9.9 million.<sup>237</sup>

Mr. Coppola states that DTE did not include a reduction in capital expenditures pertaining to the recent implementation of the Gas Scheduling Optimizer system. He adds that DTE admitted that capital savings of \$450,000 were not included as a reduction to the IT capital expenditures forecasted by DTE for the projected test year in this rate case, and thus, he recommends that this amount be removed from the projected test year capital expenditures.<sup>238</sup>

This PFD agrees with the Attorney General and recommends that the Commission adopt this proposed disallowance.

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<sup>235</sup> 3 Tr 379.

<sup>236</sup> 3 Tr 380; Ex. A-12, Sch. B5., p. 1.

<sup>237</sup> Id.

<sup>238</sup> 4 Tr 1473; Ex. AG-19.

## **Large Capital Projects**

Ms. Fedele states that From December 31, 2022, the end of the historical test year, through September 30, 2025, the end of the projected test year, DTE will have incurred \$184.3 million of large capital project expenditures.<sup>239</sup>

## **Fort Street Main Replacement Project**

Ms. Fedele states that the Fort St. Main Replacement project entails design and installation of approximately 12.9 miles of new steel and plastic main, abandonment of approximately 14.2 miles of steel main, installation of approximately 43 valves, and installation of district regulators on Fort St., Larned, Russell St., 14th 24 St., and other locations from Fort and Miller station to Jefferson Station in the city of Detroit.<sup>240</sup> She adds that this project also includes abandonment of 11 district regulators and replacement of approximately 92 services.<sup>241</sup> She states that the project is separated into eight phases for completion of the project, with the first two phases of the project being completed as a stand-alone project in 2019, with approximately 4900' of main install in phases 3 and 5 having been pulled ahead and completed in 2022 in order to coordinate with other public improvement and DTE project work, and with phases 5, 6, 7, and 7A to be completed from 2023 through 2025 in coordination with other major projects in the area.<sup>242</sup> She adds that the remainder of phase 3 and phases 4 and 8 will be completed in 2026 and 2027 in coordination with the Gordie Howe International Bridge and MDOT I-75 work.<sup>243</sup> She states that the total projected cost of the Fort Street Main Replacement project is

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<sup>239</sup> 4 Tr 1904.

<sup>240</sup> 4 Tr 1911.

<sup>241</sup> 4 Tr 1911-1912.

<sup>242</sup> 4 Tr 1912.

<sup>243</sup> 4 Tr 1912-1913, Tables 2 and 3, Figure 7.

approximately \$165.3 million of which DTE will be supporting \$68.5 million in this case.<sup>244</sup> She adds that the Fort St Main Replacement project is expected to be placed in service in phases at the end of each calendar year with final in-service and abandonment completed in 2027.<sup>245</sup>

Mr. Coppola states that Ms. Fedele stated that capital forecast for 2023 through 2025 anticipates completion of Phases 5, 6, 7, and 7A and coordination with municipal and state projects for reconstruction and modification to Jefferson Street and the I-375 7 Reconstruction project.<sup>246</sup> Mr. Coppola states that the Attorney General asked DTE to provide the timing of the I-375 Reconstruction and other applicable municipal projects that will drive the timing of the Fort Street project, and that in response DTE stated that Phase 5 was completed in 2023, Phase 7 around the Michigan Central Train Station would be completed by April 2024, and that with regard to the I-375 Reconstruction project, no timing was provided by DTE, with DTE waiting for more information from the Michigan Department of Transportation (MDOT).<sup>247</sup> He adds that although the capital spending forecasted for 2024 appears likely to occur, the capital spending for the projected test year is dependent on the timing of the I-375 Reconstruction project and MDOT has not yet defined a specific timeline, and as such, it is premature to approve capital spending on the Fort Street Main Replacement for the projected test year until there is more clarity and specific plans from MDOT for DTE to act on.<sup>248</sup> Thus, he concludes that the \$32,753,000 forecasted by DTE for the projected test year for the Fort

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<sup>244</sup> 4 Tr 1915; 1916, Ex. A-12, Sch. B5.2, Sch. B5.5.

<sup>245</sup> Id.

<sup>246</sup> 4 Tr 1449.

<sup>247</sup> 4 Tr 1449; Ex. AG-9.

<sup>248</sup> 4 Tr 1449-1450.

Street Main Replacement project are not likely to be spent and he recommends that the Commission remove that amount for DTE's forecasted capital expenditures in this rate case.<sup>249</sup>

Ms. Fedele counters that underlying Mr. Coppola's proposed disallowance is his comparison to the East Jefferson main replacement project, stating that costs can increase significantly if government agencies decide to postpone their project plans.<sup>250</sup> She adds that comparing the Fort Street Main Replacement project to the East Jefferson project is wholly inappropriate and reflects a lack of understanding of the differing circumstances between the two projects.<sup>251</sup> She asserts that in contrast to the East Jefferson project, the Fort Street Main Replacement project is a standalone project and not part of a larger municipal coordination or public improvement project.<sup>252</sup> She adds that while DTE is flexible in scheduling this work to align with municipal projects, the overall project execution and completion is not dependent on the work performed by the governmental agencies.<sup>253</sup>

This PFD agrees with the Attorney General. Although Ms. Fedele asserts in rebuttal that this project is a "standalone project and not part of a larger municipal coordination or public improvement project," this PFD notes that Ms. Fedele states in her direct testimony that Phases 5, 6, 7, and 7A will be completed from 2023 through 2025 "in coordination with other major projects in the area such as the East Jefferson project, the Detroit Grand Prix, I-375 Reconstruction, and other municipal coordination

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<sup>249</sup> 4 Tr 1450.

<sup>250</sup> 4 Tr 1980.

<sup>251</sup> Id.

<sup>252</sup> 4 Tr 1981.

<sup>253</sup> Id.

projects.”<sup>254</sup> This PFD also notes that DTE’s discovery response provides that DTE “will continue to coordinate on the I-375 Reconstruction Project as more information regarding the schedule is made available from MDOT.”<sup>255</sup> Thus, this PFD agrees with Mr. Coppola that the capital spending for the projected test year is dependent on the timing of the I-375 Reconstruction project and that it would be imprudent for DTE to proceed with construction activities without a firm timeline and an approved project plan from MDOT and the City of Detroit. Accordingly, this PFD recommends that the Commission adopt the Attorney General’s recommendation to remove the \$32,753,000 forecasted by DTE for the projected test year for the Fort Street Main Replacement project.

Ms. Fedele states that DTE has included three capital projects in this case that have not been approved by DTE: Austin-Detroit A&B Lines Project, Belle River Detroit Interconnect and Loop, and Taggart Compression Replacement.<sup>256</sup> She adds that these projects include capital investments greater than \$10 million, which will require Executive review and approvals beyond DTE Gas President level approval, and that at the time of this filing, the projects were in the earlier stages of the project life cycle, making it too soon to begin the capital project approval process.<sup>257</sup> She states that these projects have received budget approval by the DTE President for preliminary engineering work.<sup>258</sup>

These three projects shall be discussed separately.

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<sup>254</sup> 4 Tr 1912.

<sup>255</sup> Ex. AG-9, p. 1.

<sup>256</sup> 4 Tr 1908.

<sup>257</sup> 4 Tr 1906-1907.

<sup>258</sup> 4 Tr 1907.

## **Austin-Detroit A&B Lines Project**

Ms. Fedele states that DTE Gas's Austin-Detroit 24 A-Line and B-Line connect the Six Lakes storage field/Taggart Compressor station to the Southeast Michigan market, and that these pipelines transport year-round supply received at various interconnects and storage fields to DTE Gas's Detroit and Grand Rapids markets.<sup>259</sup> She adds that the Austin-Detroit A&B Pipeline Project will replace the existing pipelines installed in 1948 and 1951, respectively, through Class 3 and High Consequence Areas (HCAs).<sup>260</sup> She states that DTE Gas's A-Line and B-Line pipelines were designed and installed in 1948 and 1951, and that the characteristics of the Austin-Detroit A&B pipelines result in higher integrity risks, placing them in the top Transmission Replacement Program (TRP) pipelines needing risk remediation.<sup>261</sup> She states that DTE Gas analyzed various options and decided that the replacement of approximately 43 miles in the highly populated areas of Class 3 and HCA achieves the primary goal of reducing the integrity risks while not adversely affecting operational flexibility or increasing operational risk.<sup>262</sup> She asserts that more frequent ILI and patrols not suitable as remediation for the Austin Detroit A and B pipelines.<sup>263</sup> She states that this Austin-Detroit A&B Lines Project is a great example of how DTE Gas developed a solution to mitigate risk of outage while maintaining the system's operational flexibility in response to the Commission's recommendation set forth in section 9.3.1.2. of the Michigan Statewide Energy Assessment (SEA) final report issued September 11, 2019.<sup>264</sup>

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<sup>259</sup> 4 Tr 1916-1917.

<sup>260</sup> 4 Tr 1917.

<sup>261</sup> 4 Tr 1918.

<sup>262</sup> 4 Tr 1920.

<sup>263</sup> 4 Tr 1921.

<sup>264</sup> 4 Tr 1923.

Ms. Fedele states that construction is planned to be in phases and will begin in 2026 and continue through 2028.<sup>265</sup> She adds that the total projected capital expenditure for the Austin-Detroit A&B Lines Project is estimated to be \$308.5 million spanning from 2022 to 2028, with \$21.0 million identified in this proceeding representing a portion of the total project capital expenditures that will be incurred from December 31, 2022, the end of the historical test year through September 30, 2025, the end of the projected test year.<sup>266</sup> She states that the Austin-Detroit A&B Lines project does not have capital project approval yet as the project is in the earlier stages of the project life cycle, but that this project has received budget approval by the President of DTE Gas for preliminary engineering work with capital project approval being planned by May 30, 2025.<sup>267</sup>

Ms. Fedele states that from December 31, 2022, the end of the historical test year, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$24.9 million, including costs for the conceptual engineering for the project which began in 2023.<sup>268</sup> She adds that the detailed engineering and initial material acquisition is planned for 2024 and will continue into 2025, and that at the end of 2025, approximately 10 miles of the 43 total will be on hand for construction in 2026.<sup>269</sup> She states that because this is a capital project that spans multiple years in several phases, none of which will be placed in service during the projected test year, there is no revenue deficiency related to this project in DTE's revenue requirement in this case.<sup>270</sup>

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<sup>265</sup> 4 Tr 1924.

<sup>266</sup> 4 Tr 1924-1925, Table 7.

<sup>267</sup> 4 Tr 1925.

<sup>268</sup> Id.

<sup>269</sup> 4 Tr 1925-1926, Ex. A-12, Sch. B5.5.

<sup>270</sup> 4 Tr 1926.

Mr. Coppola states that Ms. Fedele identifies three projects that have not yet received formal corporate approval to proceed with project development: the Austin-Detroit A&B Lines replacement, the Belle River/Detroit Interconnect & Loop, and the Taggart Compressor Replacement.<sup>271</sup> He adds that those projects have not yet completed the engineering design phase and will not be placed in service until well past the end of the projected test year.<sup>272</sup> He states that the total forecasted capital expenditures for the three projects are \$1.3 million for 2023, \$4.7 million for the 9 months ending September 2024, and \$27.1 million for the projected test year.<sup>273</sup> He concludes that these projects have not yet been approved and are still in the early phase of development with no assured timeline and thus premature to include in rate base in this rate case, irrespective of the fact that an Allowance for Funds Used During Construction (AFUDC) cost offset has been recorded to operating income, and thus, he recommends that the Commission remove the capital expenditures of \$1.3 million for 2023, \$4.7 million for the 9 months ending September 2024, and \$27.1 million for the projected test year.<sup>274</sup>

This PFD notes that Ms. Fedele does not offer any rebuttal testimony regarding the Austin-Detroit A&B Lines project.<sup>275</sup>

This PFD agrees with the Attorney General that it is not reasonable to include forecasted expenditures for these projects which have not yet completed the engineering design phase and will not be placed in service until well past the end of the projected test year. Thus, this PFD recommends that the Commission agrees to remove the total

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<sup>271</sup> 4 Tr 1463.

<sup>272</sup> 4 Tr 1463-1464.

<sup>273</sup> 4 Tr 1464; Ex. A-12, Sch. B5.2.

<sup>274</sup> 4 Tr 1464-1465. DTE mistakenly asserts in its initial brief that no party opposes the request for these three projects. See DTE initial brief, p. 35, 40, 44.

<sup>275</sup> 4 Tr 1977-1990.

forecasted capital expenditures for the three projects -- \$1.3 million for 2023, \$4.7 million for the 9 months ending September 2024, and \$27.1 million for the projected test year -- from construction work in process and rate base.

### **Van Born Project**

Ms. Fedele states that the Van Born System consists of two pipelines; a 30" 540 psig pipeline that supplies natural gas to two large industrial customers and one city gate station, and a 36" 300 psig pipeline that is a primary source of natural gas supply to the DTE Gas southeast markets.<sup>276</sup> She adds that the Van Born Project entails the installation of new regulation at DTE Gas's Rouge Station that allows gas from the 30" 540 psig pipeline to flow into the 36" 300 psig system.<sup>277</sup> She states that three existing main line valves along the 36" pipeline will be modified to permit remote control operation from DTE Gas Control and that two new main line valves with remote control capabilities will be installed along the 36" pipeline to further segment the pipeline into additional sections.<sup>278</sup> She asserts that DTE Gas evaluates the Van Born System as a higher risk area needing mitigation of customer outage risks.<sup>279</sup>

Ms. Fedele states that since the last general rate case (Case No. U-20940), the project progressed to where detailed engineering was 90% complete and where DTE solicited construction bids from 10 prospective contractors.<sup>280</sup> She adds that the cost estimate for the project increased from the conceptual estimate of \$96.0 million to a

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<sup>276</sup> 4 Tr 1926.

<sup>277</sup> Id.

<sup>278</sup> 4 Tr 1926-1927.

<sup>279</sup> 4 Tr 1927; 1930, Table 8.

<sup>280</sup> 4 Tr 1932.

detailed engineering estimate of \$185.4 million, with the difference being primarily attributed to the refinement of the project's scope, an increase of the material cost and higher than expected construction costs.<sup>281</sup> She states that DTE chose the option which involves the installation and retrofitting of Main Line Valves (MLVs) with remote capability and construction of new regulation at Rouge Station.<sup>282</sup>

Ms. Fedele states that the Van Born Project consists of seven (7) unique construction sites with five of these sites will be placed into service on or before January 31, 2024 and with the remaining two locations being constructed and placed into service upon completion by October 2024.<sup>283</sup> She adds that the total actual capital expenditures incurred on the Van Born Project from 2020 to August 31, 2023, is \$40.6 million.<sup>284</sup> She states that previously DTE Gas Co. withdrew its application filed in December 2021 (U-21119) requesting Ex-Parte Order for Certificate of Public Convenience and Necessity under Act 9 to construct and operate the West Van Born Pipeline and Facilities project in Washtenaw and Wayne counties as it identified an alternative and more cost-effective way to prevent a large customer outage.<sup>285</sup> She adds that in June 2022, approximately \$1.9 million capital charges related to this project were charged to O&M.<sup>286</sup> She states that the credit/write off expenditure of approximately \$1.9 million of capital expenditures has been included in this case, with the subsequent \$1.9

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<sup>281</sup> Id.

<sup>282</sup> 4 Tr 1933, Table 9.

<sup>283</sup> 4 Tr 1935.

<sup>284</sup> Id., Table 10.

<sup>285</sup> 4 Tr 1935.

<sup>286</sup> Id.

million charge/write off to O&M not being included in projected O&M.<sup>287</sup> She adds that from December 31, 2022, the end of the historical test year, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$42.7 million of Van Born Project capital expenditures.<sup>288</sup>

Mr. Coppola states that DTE proposed a different and larger project in the two prior rate cases, and that DTE revised its plans and project designs in May 2022 to achieve the same objective at a much lower cost.<sup>289</sup> He adds that from 2020 to May 2022, DTE incurred \$8.7 million in capital costs related to the project and that DTE wrote-off to expense \$1.9 million (rounded up to \$2 million) of the project costs incurred related to the previous project.<sup>290</sup> He states that in response to discovery request DTE identified the components of the \$1.9 million, which were rounded up to \$2.0 million, but did not identify what the remaining \$6.7 million were specifically spent on and why they should remain in rate base, noting that most of the remaining costs have been categorized as contracted services, labor, and overheads.<sup>291</sup> He asserts that with the project changing significantly from its initial scope and DTE filing an expensive Act 9 application, which it subsequently withdrew after the project scope changed, the \$1.9 million write-off seems considerably insufficient.<sup>292</sup> He concludes that given the lack of transparency for the remaining \$6.7

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<sup>287</sup> 4 Tr 1936-1937.

<sup>288</sup> 4 Tr 1937, Ex. A-12, Sch. B5.2, Sch. B5.5.

<sup>289</sup> 4 Tr 1451.

<sup>290</sup> Id.

<sup>291</sup>

<sup>292</sup> Id.

million of project costs incurred prior to May 2022, he recommends that the Commission remove this amount from rate base in this rate case.<sup>293</sup>

Ms. Fedele counters that DTE has been fully transparent regarding the costs for the Van Born project.<sup>294</sup> She adds that in May 2022, the decision was made to remove certain aspects of the project, while leaving all other aspects of the project as originally planned.<sup>295</sup> She states that through May 2022, the project had incurred expenses of \$8.7 million and that DTE subsequently removed \$2 million, leaving the remaining \$6.7 million, which was the actual cost to perform the engineering design, project management, land acquisition and other project activities associated with the modified Van Born project scope.<sup>296</sup> She asserts that the \$6.7 million in expenditures in dispute were reasonable and prudent.<sup>297</sup>

This PFD agrees that DTE has supported the nature and amount of these expenditures, and thus recommends that the Commission not accept the attorney General's proposed disallowance.

### **Belle River Dehydration Unit**

Ms. Fedele states that the Belle River Dehydration Unit Project is the addition of a Tri-Ethylene Glycol (TEG) dehydration unit at Belle River compressor station.<sup>298</sup> She adds that the Belle River storage field accounts for nearly 40% of system requirements on a winter design day, that DTE Gas does not have redundant storage processing equipment

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<sup>293</sup> 4 Tr 1452.

<sup>294</sup> 4 Tr 1982.

<sup>295</sup> Id.

<sup>296</sup> Id.

<sup>297</sup> 4 Tr 1983.

<sup>298</sup> 4 Tr 1937.

(dehydration equipment) at this facility and, therefore, failure of the Belle River dehydration unit could significantly impact DTE Gas' ability to serve its customers on a winter design day.<sup>299</sup> She states that in the past 10 years the dehydration unit at Belle River failed four times.<sup>300</sup> She notes that the most recent dehydration failure in December of 2022 occurred in conjunction with dehydration failures at Columbus station during a period of very cold weather, which resulted in an Operational Flow Order (OFO).<sup>301</sup> She asserts that the Belle River Dehydration Unit Project will provide 100% redundancy in the event of an emergency outage on the existing unit.<sup>302</sup>

Ms. Fedele states that the Belle River Dehydration Unit will be placed into service prior to November 2024 to be ready for the 2024/2025 heating season.<sup>303</sup> She adds that the total projected capital expenditure for the Belle River Dehydration Plant Project is estimated to be \$28.5 million spanning from 2022 to 2025, and that the \$25.6 million identified in this proceeding represents a portion of the total project capital expenditures that will be incurred from December 31, 2022, the end of the historical test year through September 30, 2025, the end of the projected test year.<sup>304</sup> She adds that this project requires a capital investment greater than \$10 million and has received the required Executive review and approvals for capital project approval.<sup>305</sup>

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<sup>299</sup> 4 Tr 1939.

<sup>300</sup> 4 Tr 1940, Table 11.

<sup>301</sup> 4 Tr 1940-1941.

<sup>302</sup> 4 Tr 1942.

<sup>303</sup> Id.

<sup>304</sup> 4 Tr 1942-1943, Table 12; Ex. A-14, Sch. B5.2, B5.5.

<sup>305</sup> 4 Tr 1942.

## **Belle River - Detroit Interconnect And Loop Project**

Ms. Fedele states that The Belle River – Detroit System consists of a 1962 vintage, 24” transmission pipeline known as the Belle River – Detroit Pipeline, the Northeast Gate Station, and 1962 vintage 26” transmission pipeline downstream of the gate station that is operated by Distribution known as the East Outer Drive Pipeline.<sup>306</sup> She adds that this system is a primary source of natural gas supply from the northeast to the DTE Gas southeast market.<sup>307</sup> She states that the Belle River – Detroit Interconnect and Loop Project consists of a new interconnection with Consumers Energy at a point where their 26” Line 1700 pipeline and the DTE Gas 24” Belle River – Detroit Pipeline intersect and a new 6-mile, 24” pipeline loop that will provide an alternate supply into DTE Gas’s Northeast Station.<sup>308</sup> She adds that a Non-Binding Memorandum of Understanding was executed between DTE Gas and Consumers Energy on April 1, 2021, where Consumers Energy would provide supply to DTE Gas through the interconnect in the event of an emergency on the DTE Gas system, providing that they are operationally able to.<sup>309</sup> She states that the Belle River – Detroit Pipeline is the primary gas supply into the northeast portion of the DTE Gas southeast market area, and the lack of redundant supply increases outage risk.<sup>310</sup> She adds that an Act 9 application is necessary for this project, which DTE plans to submit on or before April 30, 2025.<sup>311</sup> She states that the Belle River

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<sup>306</sup> 4 Tr 1944.

<sup>307</sup> Id.

<sup>308</sup> 4 Tr 1944-1945, Figure 11.

<sup>309</sup> 4 Tr 1944.

<sup>310</sup> 4 Tr 1946.

<sup>311</sup> 4 Tr 1950.

– Detroit Interconnect and Loop Project is planned to be placed into service in January 2027.<sup>312</sup>

Ms. Fedele states that the total projected capital expenditure for the Belle River Detroit Interconnect and Loop Project is estimated to be \$52.1 million spanning from 2024 to 2027, and that the \$8.1 million identified in this proceeding represents the initial portion of the total project capital expenditures that will be incurred from December 31, 2022, the end of the historical test year through September 30, 2025, the end of the projected test year.<sup>313</sup> She states that DTE Gas will incur expenses of approximately \$3.6 million to prepare the submission of an accurate and detailed Act 9 Application.<sup>314</sup> She adds that the Belle-River-Detroit Interconnect and Loop project does not have capital project approval yet, but that the project has received budget approval by the President of DTE Gas for preliminary engineering work and capital project approval is planned by June 30, 2025.<sup>315</sup> She states that there is no revenue deficiency related to this project in DTE's revenue requirement in this case.<sup>316</sup>

As discussed, *supra*, Mr. Coppola states that Ms. Fedele identifies three projects that have not yet received formal corporate approval to proceed with project development: the Austin-Detroit A&B Lines replacement, the Belle River/Detroit Interconnect & Loop, and the Taggart Compressor Replacement.<sup>317</sup> He adds that those projects have not yet completed the engineering design phase and will not be placed in service until well past

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<sup>312</sup> 4 Tr 1951.

<sup>313</sup> 4 Tr 1951-1952, Table 13; Ex. A-12, Sch. B5.2, B5.5.

<sup>314</sup> 4 Tr 1953.

<sup>315</sup> 4 Tr 1953-1954.

<sup>316</sup> 4 Tr 1954.

<sup>317</sup> 4 Tr 1463.

the end of the projected test year.<sup>318</sup> He states that the total forecasted capital expenditures for the three projects are \$1.3 million for 2023, \$4.7 million for the 9 months ending September 2024, and \$27.1 million for the projected test year.<sup>319</sup> He concludes that these projects have not yet been approved and are still in the early phase of development with no assured timeline and thus premature to include in rate base in this rate case, irrespective of the fact that an Allowance for Funds Used During Construction (AFUDC) cost offset has been recorded to operating income, and thus, he recommends that the Commission remove the capital expenditures of \$1.3 million for 2023, \$4.7 million for the 9 months ending September 2024, and \$27.1 million for the projected test year.<sup>320</sup>

This PFD notes that Ms. Fedele does not offer any rebuttal testimony regarding the Belle River – Detroit Interconnect and Loop project.<sup>321</sup>

This PFD agrees with the Attorney General that it is not reasonable to include forecasted expenditures for these projects which have not yet completed the engineering design phase and will not be placed in service until well past the end of the projected test year. Thus, as discussed, this PFD recommends that the Commission agree to remove the total forecasted capital expenditures for the three projects -- \$1.3 million for 2023, \$4.7 million for the 9 months ending September 2024, and \$27.1 million for the projected test year -- from construction work in process and rate base.

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<sup>318</sup> 4 Tr 1463-1464.

<sup>319</sup> 4 Tr 1464; Ex. A-12, Sch. B5.2.

<sup>320</sup> 4 Tr 1464-1465. DTE mistakenly asserts in its initial brief that no party opposes the request for these three projects. See DTE initial brief, p. 35, 40, 44.

<sup>321</sup> 4 Tr 1977-1990.

## **CMS Line 2700 & DTE Gas E-Line Interconnect Project**

Ms. Fedele states that the CMS Line 2700 and DTE Gas E-Line interconnect consists of the installation of a bi-directional meter strategically located where each company's pipeline is in close proximity to each other.<sup>322</sup> She adds that the CMS Line 2700 & DTE E-Line Interconnect project is a joint project entered into by Consumers Energy and DTE Gas as a response to the Commission's recommendation for the utilities to consider a new transmission interconnection to increase the reliability of the natural gas system in Michigan.<sup>323</sup>

Ms. Fedele states that the CMS Line 2700 & DTE Gas E-Line Interconnection Project will be placed into service on November 30, 2025, in time for the 2025 - 2026 heating season.<sup>324</sup> She adds that the total projected capital expenditure for the CMS Line 2700 & DTE Gas Interconnect Project is estimated to be \$9.1 million spanning from 2023 to 2026.<sup>325</sup> She states that this project has received budget approval by the President of DTE Gas for preliminary engineering work and final budget approval is planned in January 2025.<sup>326</sup> She adds that from December 31, 2022, the end of the historical test year, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$6.7 million of CMS Line 2700 & DTE Gas E-Line Interconnect Project capital expenditures.<sup>327</sup>

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<sup>322</sup> Id.

<sup>323</sup> 4 Tr 1955.

<sup>324</sup> 4 Tr 1956.

<sup>325</sup> 4 Tr 1956-1957, Table 15.

<sup>326</sup> 4 Tr 1957.

<sup>327</sup> 4 Tr 1958; Ex. A-12, Sch. B5.5.

Mr. Coppola states that engineering design work on the project has not yet been completed, the project appears to be still in the conceptual design phase, and the project will not be in service until after the end of the projected test year for this rate case.<sup>328</sup> He asserts that it is premature to include this project in rate base in this rate case.<sup>329</sup> Thus, he recommends that the Commission disallow the forecasted capital expenditures of \$100,000 for 2023, \$1.1 million for the 9 months ending September 2024, and \$4.7 million for the projected test year.<sup>330</sup>

Ms. Fedele counters that since the date of filing, the project is progressing beyond the conceptual phase and is well into the detailed design phase as demonstrated by the joint Act-9 filing (U-21510) that was submitted on January 26, 2024.<sup>331</sup> She adds that the remaining detailed engineering work and material procurement will be completed in 2024, and that construction will be completed during the 2025 construction season, which is within the projected test year.<sup>332</sup> She states that the in-service date for this project is November 2025, which date falls outside of the test period ending September 30, 2025.<sup>333</sup> She states that the CMS Line 2700 & DTE Gas E-Line 10 Interconnect special project is expected to remain under construction past September 2025, there is no depreciation expense projected for these projects, and the AFUDC credit on the income statement offsets the impact of reflecting projects in rate base, thereby eliminating any revenue

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<sup>328</sup> 4 Tr 1465; Ex. A-12, Sch. B5.3.

<sup>329</sup> Id.

<sup>330</sup> Id.

<sup>331</sup> 4 Tr 1984.

<sup>332</sup> Id.

<sup>333</sup> 4 Tr 1985.

requirement for these projects.<sup>334</sup> She asserts that should the Commission disallow any of the capital investment related to these special projects in their final order, the Commission must also make a corresponding and offsetting reduction in the AFUDC credit in the income statement that was included in the filing.<sup>335</sup>

This PFD finds that DTE has adequately supported this projected expenditure. Thus, this PFD recommends that the Commission reject the Attorney General's proposed disallowance.

### **DTE Gas Site Security Program**

Ms. Fedele states that the DTE Gas Site Security Program is attempting to mitigate three key areas of risk: a) Physical Security, b) Cyber Security, and c) Facility Protection.<sup>336</sup> She adds that physical security projects include new chain link fences, retrofit of existing fences with barbed wire, installation/upgrade of egress gates, automation of main and secondary access gates, installation of cameras/Video Surveillance System (VSS), installation of intrusion detection systems, installation of new/standardized door locks and lock management systems for critical buildings and Physical Access Control System (PACS); cyber security projects include operational technology (OT) enhancements, device/network activity monitoring systems, enhanced log-in systems, and malicious threat protection and security patching; and facility protection projects were developed to install engineered crash rated gates and fences,

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<sup>334</sup> Id. Citation omitted.

<sup>335</sup> Id.

<sup>336</sup> 4 Tr 1959.

guard rails, concrete barriers and bollards at each facility.<sup>337</sup> She states that the total expected capital expenditures for the DTE Gas Site Security Program are \$25.2 million.<sup>338</sup> She adds that from December 31, 2022, the end of the historical test year, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$8.3 million of DTE Gas Site Security Program capital expenditures.<sup>339</sup>

### **Taggart Compressor Replacement Project**

Ms. Fedele states that DTE Gas is developing a Compression Replacement Program (CRP) to renew the compression fleet to mitigate risk and sustain reliable service.<sup>340</sup> She adds that the CRP will prioritize replacing assets based on unit age, utilization, spare parts availability, and reliability, and the program will optimize asset replacement to increase utilization without sacrificing redundancy.<sup>341</sup>

Ms. Fedele states that the Taggart Compressor Replacement Project involves the oldest units in the DTE fleet which are located at Taggart Compressor Station.<sup>342</sup> She adds that the Taggart Compressor Station units need to be replaced because there are multiple critical parts on the units that are obsolete and no longer supported by the original equipment manufacturer (OEM), and that for parts that are still supported by the OEM or available from alternative suppliers, lead times are increasing due to reduced demand for these style compressor units.<sup>343</sup>

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<sup>337</sup> 4 Tr 1961.

<sup>338</sup> 4 Tr 1962, Table 16.

<sup>339</sup> 4 Tr 1963; Ex. A-12, Sch. B5.2, Sch. B5.5.

<sup>340</sup> Id.

<sup>341</sup> 4 Tr 1964.

<sup>342</sup> 4 Tr 1965.

<sup>343</sup> 4 Tr 1966.

Ms. Fedele states that the Taggart Compressor Replacement project is expected to be placed in service in 2027, and that the total projected capital expenditure for the Taggart Compressor Replacement Project is estimated to be \$100.0 million spanning from 2024 to 2027.<sup>344</sup> She adds that this project has received budget approval by the President of DTE Gas for preliminary engineering work and capital project approval is planned on or before June 30, 2025.<sup>345</sup> She states that from December 31, 2022, the end of the historical test year, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$4.0 million of Taggart Compressor Replacement Project capital expenditures.<sup>346</sup>

As discussed, *supra*, Mr. Coppola states that Ms. Fedele identifies three projects that have not yet received formal corporate approval to proceed with project development: the Austin-Detroit A&B Lines replacement, the Belle River/Detroit Interconnect & 18 Loop, and the Taggart Compressor Replacement.<sup>347</sup> He adds that those projects have not yet completed the engineering design phase and will not be placed in service until well past the end of the projected test year.<sup>348</sup> He states that the total forecasted capital expenditures for the three projects are \$1.3 million for 2023, \$4.7 million for the 9 months ending September 2024, and \$27.1 million for the projected test year.<sup>349</sup> He concludes that these projects have not yet been approved and are still in the early phase of development with no assured timeline and thus premature to include in rate base in this

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<sup>344</sup> 4 Tr 1968, Table 18.

<sup>345</sup> 4 Tr 1968-1969.

<sup>346</sup> 4 Tr 1969; Ex. A-12, Sch. B5.2, Sch. B5.5.

<sup>347</sup> 4 Tr 1463.

<sup>348</sup> 4 Tr 1463-1464.

<sup>349</sup> 4 Tr 1464; Ex. A-12, Sch. B5.2.

rate case, irrespective of the fact that an Allowance for Funds Used During Construction (AFUDC) cost offset has been recorded to operating income, and thus, he recommends that the Commission remove the capital expenditures of \$1.3 million for 2023, \$4.7 million for the 9 months ending September 2024, and \$27.1 million for the projected test year.<sup>350</sup>

This PFD notes that Ms. Fedele does not offer any rebuttal testimony regarding the Taggart Compressor Replacement project.<sup>351</sup>

This PFD agrees with the Attorney General that it is not reasonable to include forecasted expenditures for these projects which have not yet completed the engineering design phase and will not be placed in service until well past the end of the projected test year. Thus, as discussed, this PFD recommends that the Commission agrees to remove the total forecasted capital expenditures for the three projects -- \$1.3 million for 2023, \$4.7 million for the 9 months ending September 2024, and \$27.1 million for the projected test year -- from construction work in process and rate base.

#### **Traverse City / Alpena Reinforcement Project**

Ms. Fedele states that the Traverse City / Alpena Reinforcement Project (TCARP) entails looping the existing Lincoln-Traverse City pipeline with approximately 8.8 miles of 10" diameter pipe and looping the existing Frankfort pipeline with 14.4 miles of 8" diameter pipe; installation of six (6) interconnects with pipelines owned by DTM Michigan Gathering Holding Company (DT Midstream); installation of one (1) new gate station near Manistee; and modifications to twelve (12) existing gate stations.<sup>352</sup> She adds that the project was

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<sup>350</sup> 4 Tr 1464-1465. DTE mistakenly asserts in its initial brief that no party opposes the request for these three projects. See DTE initial brief, p. 35, 40, 44.

<sup>351</sup> 4 Tr 1977-1990.

<sup>352</sup> 4 Tr 1970.

divided into 3 phases. Phase 1, construction of 8.8 miles of Lincoln-Traverse City 10” loop pipeline and associated stations, was placed into service at the end of January 2021; Phase 2, construction of 14.4 miles of Frankfort 8” loop pipeline and associated stations was placed into service in January 2022, and Phase 3, construction of the interconnections with DT Midstream, were placed into service in February 2023.<sup>353</sup> She states that the DTE Gas capital cost or annual demand charge for the TCARP project has changed from DTE Gas’s previous filing in Case No. U-20940, whereby in the previous case, the TCARP capital cost was \$100.8 million, and the demand charge was \$11.6M, while in this case, the capital cost is \$114.8 million, and the annual demand is \$10.7 million.<sup>354</sup> She adds that as filed in Case No. U-20940, the expected first-year annual residential customer bill impact of TCARP was approximately \$14, while the first-year annual residential customer bill impact is now expected to be approximately \$13.<sup>355</sup> She states that these costs were not included in determining the revenue requirement in Case No. U-20940 and that rates established in this rate case will reflect the TCARP costs.<sup>356</sup> She adds that DTE Gas is projecting the total capital cost for the TCARP project to be \$114.8 million, an increase of \$14.0 million.<sup>357</sup>

Ms. Fedele states that DTE Gas’s total capital cost for the TCARP project is \$114.8 million.<sup>358</sup> She adds that from December 31, 2022, the end of the historical test year,

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<sup>353</sup> Id.

<sup>354</sup> 4 Tr 1971-1972, Table 19.

<sup>355</sup> 4 Tr 1973.

<sup>356</sup> Id.

<sup>357</sup> Id.

<sup>358</sup> 4 Tr 1975, Table 20.

through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$3.4 million of Traverse City / Alpena Reinforcement Project capital expenditures.<sup>359</sup>

Mr. Coppola notes that Ms. Fedele states that the cost of the project increased from the initial estimate of \$100.8 million to a final cost of \$114.8 million and that she attributes the higher cost of the project to three factors: (1) \$3.0 million due to the one-year delay by DT Midstream Michigan Lateral Company (DTMLC) in receiving its Act 9 certificate to build a portion of the project, (2) \$9.8 million due to higher construction costs than previously estimated, and (3) \$1.2 million to add pressure regulators not previously anticipated.<sup>360</sup> He asserts that the Attorney General asked DTE to explain why the one-year delay would cause an additional \$3.0 million in higher internal labor costs, higher contractor and material costs, and higher corporate overhead costs, and to provide the amount related to each item.<sup>361</sup> He states that in response, DTE repeated the reason for the project delay but failed to explain why the delay would cause internal labor to increase by \$1,800,000, overhead costs to increase by \$1,100,000, and contractor and material costs to increase by \$50,000 each and provides no justification for the higher costs.<sup>362</sup> He adds that although the delay seems plausible due to the Act 9 proceedings, no work took place during that time and no new employees were hired to justify the additional \$1.8 million of internal labor costs while DTE waited for DTMLC to obtain the Act 9 certificate,

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<sup>359</sup> 4 Tr 1975-1976; Ex. A-12, Sch. B5.2.

<sup>360</sup> 4 Tr 1465-1466; Ex. AG-16.

<sup>361</sup> 4 Tr 1466.

<sup>362</sup> 4 Tr 1465-1466; Ex. AG-16.

that the overhead costs of \$1.1 million follow the labor cost and at 61% seem excessive, and that the additional contractor and material costs are confusing given than the project was on hold during the one-year period.<sup>363</sup> He states that DTE has failed to adequately justify the additional \$3.0 million in project costs, mostly arising from internal labor and overheads.<sup>364</sup> Thus, he recommends that the Commission remove the \$3.0 million from rate base in this case and instruct DTE to also remove the amount permanently from future rate cases.<sup>365</sup>

Mr. Coppola states that in a prior case, DTE Gas incurred additional costs to build temporary facilities to correct a problem with excessive moisture in the gas stream transported by DTMLC to the DTE Gas pipeline system, with DTE Gas admitting that it should have billed the incremental costs to DTMLC and instead included them in rate base, which it seeks to recover in this rate case.<sup>366</sup> He adds that in response to further discovery on this matter in this rate case, DTE identified the total incremental costs to be \$323,000, consisting of \$155,000 to build the Saginaw Bay interconnect loop and \$168,000 for the West Branch interconnect loop.<sup>367</sup> Thus, he recommends that the Commission remove the \$323,000 from rate base in this case and instruct DTE to remove the amount permanently from future rate cases.<sup>368</sup>

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<sup>363</sup> 4 Tr 1466; Ex. AG-16.

<sup>364</sup> Id.

<sup>365</sup> 4 Tr 1466-1467.

<sup>366</sup> 4 Tr 1467; Ex. AG-16.

<sup>367</sup> Id.

<sup>368</sup> Id.

Ms. Fedele counters that Phase 2 and Phase 3 were both planned to be completed in 2021 using the same resources but were separated into two years to better align with DTM's in-service date.<sup>369</sup> She adds that Phase 1 construction occurred in 2020 with an annual spend of \$31.0 million which includes internal labor costs of \$2.0 million (6.3%); Phase 2 construction occurred in 2021 with a total annual spend of \$32.6 million, including an internal labor component of \$2.3 million (7.1%); and Phase 3 construction occurred in 2022 with an annual spend of \$40.7 million, including an internal labor component of \$2.7 million (6.7%).<sup>370</sup> She states that the internal labor costs are used to support the safe and successful construction and are comprised of engineering, project management, material coordination and verification, construction oversight, operational staff, and internal construction team to perform the stopple installations.<sup>371</sup> She adds that contained within the \$2.7 million internal labor component in 2022 was the additional \$1.8 million needed to complete the project, and that by extending Phase 3 out an additional year, the cost of the corporate overheads also increased.<sup>372</sup>

This PFD agrees with the Attorney General. While DTE offers a reasonable explanation for the delay of the project, DTE fails to offer any explanation for why the delay would cause internal labor to increase by \$1,800,000, overhead costs to increase by \$1,100,000, and contractor and material costs to increase by \$50,000 each when no work took place and no new employees were hired while DTE waited for DTMLC to obtain

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<sup>369</sup> 4 Tr 1986.

<sup>370</sup> Id.

<sup>371</sup> 4 Tr 1986-1987.

<sup>372</sup> 4 Tr 1987.

the Act 9 certificate. Thus, this PFD recommends that the Commission adopt the Attorney General's proposed disallowance of \$3.0 million from rate base in this case and instruct DTE to also remove the amount permanently from future rate cases. In addition, this PFD notes that neither Ms. Fedele nor DTE in its brief rebuts Mr. Coppola's assertions about the \$323,000 in additional incremental costs that DTE seeks in this case. As such, this PFD recommends that the Commission adopt the Attorney General's recommendation to remove the \$323,000 from rate base in this case and to instruct DTE to remove the amount permanently from future rate cases.

### **General Intervenor Proposed Changes to Capital Projects**

Mr. Fitzhenry states that several of the largest capital projects are not expected to be In-Service until after September 30, 2025, the end of the projected test year.<sup>373</sup> He adds that if any of these projects experience unforeseen delays due to permitting, labor shortages, material delays, or unforeseen site conditions, it is unlikely that the capital investment being requested by DTE will be realized prior to the end of the projected test year.<sup>374</sup> He asserts that DTE has historically experienced issues with large capital project delays.<sup>375</sup> He adds that project delays can create a squeezing effect on the rate case historical and future test year periods, where both historical and future capital expenditures are included in customer rates despite the fact that not all of the proposed capital investments have been placed into service.<sup>376</sup> He recommends a reduction in the proposed capital expenditures in the future test year period to ensure customers will not

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<sup>373</sup> 4 Tr 1319.

<sup>374</sup> Id.

<sup>375</sup> Id.

<sup>376</sup> 4 Tr 1320.

have capital investment included in rates for work that was not completed.<sup>377</sup> He proposes removing the last six months of DTE's proposed capital investment for the projects shown from the projected test year to adjust the level of capital investment, which removes approximately \$40 million of proposed capital expenditures from the projected test year.<sup>378</sup>

Ms. Fedele counters that Mr. Fitzhenry has made a general assumption that all projects listed in his Table CTF-4 will be impacted by project delays due to unforeseen conditions.<sup>379</sup> She adds that Mr. Fitzhenry's adjustment to remove the last six months of DTE's proposed capital investments lacks any supporting evidence specific to the costs he is proposing to disallow.<sup>380</sup> She asserts that DTE intentionally decided to postpone the construction of Phase 3 of the Traverse City Reinforcement project from 2021 into 2022 to allow the completion of Phase 3 to more closely align with DTM's in-service date.<sup>381</sup>

This PFD agrees that ABATE has not provided evidence supporting specific delays tied to the requested capital expenditures. As such, this PFD recommends that the Commission reject ABATE's proposed disallowance.

ABATE asserts that several of the proposed capital projects are not expected to be In-Service until after September 30, 2025, the end of the projected test year.<sup>382</sup> Mr. Fitzhenry states that if any of these projects experience unforeseen delays due to permitting, labor shortages, material delays, or unforeseen site conditions, it is unlikely that the capital investment being requested by DTE will be realized prior to the end of the

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<sup>377</sup> Id.

<sup>378</sup> Id.

<sup>379</sup> 4 Tr 1988.

<sup>380</sup> Id.

<sup>381</sup> 4 Tr 1989.

<sup>382</sup> 4 Tr 1319.

projected test year.<sup>383</sup> He asserts that DTE historically has experienced issues with large capital project delays.<sup>384</sup> He asserts that project delays if any of these projects experience unforeseen delays due to permitting, labor shortages, material delays, or unforeseen site conditions, it is unlikely that the capital investment being requested by DTE will be realized prior to the end of the projected test year.<sup>385</sup>

Mr. Fitzhenry recommends a reduction in the proposed capital expenditures in the future test year period to ensure customers will not have capital investment included in rates for work that was not completed.<sup>386</sup> In that regard, he removed the last six months (April 2025 through September 2025) of DTE's proposed capital investment for the following various projects from the projected test year to adjust the level of capital investment: Fort Street Main Replacement (\$16,799,000), b) Austin-Detroit AB Lines (\$9,778,000, Belle River -Detroit Interconnect and Loop (\$4,750,000), E-line Interconnect (CMS Line 2700) (\$2,937,000), ILI Expansion – Muskegon – Ludington (\$2,051,000), Taggart Compressor Replacement (\$2,000,000), and ILI Expansion – Belle River Field Headers (\$1,632,000).<sup>387</sup>

DTE counters that the potential for delays is inherent in any capital project and already accounted for in cost and schedule contingency.<sup>388</sup> DTE adds that its intentional decision to postpone the construction of phase three of the Traverse City Reinforcement

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<sup>383</sup> Id.

<sup>384</sup> Id.

<sup>385</sup> 4 Tr 1320.

<sup>386</sup> Id.

<sup>387</sup> 4 Tr 1320-1321, Table CTF-4.

<sup>388</sup> DTE initial brief, p. 46.

project from 2021 to 2022 is not indicative of fatal flaws in the project timelines for each of its large capital projects.<sup>389</sup>

This PFD agrees with DTE. While ABATE's concerns are well-taken, ABATE proposes broad-based adjustments that are not supported by its evidence. Moreover, this PFD notes that it is recommending the adoption of larger disallowances for most of the projects ABATE references. Thus, this PFD recommends that the Commission reject ABATE's proposed disallowances.

CUB asserts that the use of an average of 2022 and 2023 historical data as a proxy for the test year is appropriate for this rate case.<sup>390</sup> Mr. Veerapaneni asserts that the capital expenses related to the categories described in Exhibit CUB-2 should be \$713,811,000, which results in a reduction of \$5,868,000.<sup>391</sup> Noting that DTE supports the historical amounts for 2022 and 2023 for the capital expenditures in Routine, Large Capital Projects, and IRM categories, Mr. Veerapaneni states that he is proposing adjustments to the capital expenditures proposed by DTE by using the 2023 actual amounts provided in DTE's discovery response.<sup>392</sup> He asks that the Commission use average historical data for 2022 and 2023 and the adjustments shown in Exhibit CUB-3 for capital expenses as a proxy for the test year ending on September 30, 2025.<sup>393</sup> He states that the proposed rate increase is significant and is extremely burdensome for residential rate payers considering current economic conditions, and he urges the

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<sup>389</sup> Id.

<sup>390</sup> 4 Tr 943.

<sup>391</sup> 4 Tr 941; Ex. CUB-2, CUB-3.

<sup>392</sup> 4 Tr 944; Ex. CUB-3.

<sup>393</sup> 4 Tr 946.

Commission to consider the current economic disruptions experienced by ratepayers in considering the significant rate increase proposed by DTE.<sup>394</sup>

Ms. Fedele counters that using 2022 and 2023 historical capital spending as a proxy for the test year ending September 30, 2025, is inappropriate as it does not account for capital planned to be incurred in 2024 and 2025.<sup>395</sup> DTE asserts that relying on historic figures alone fails to capture the known and measurable capital expenditures scheduled to support DTE's large capital projects in 2024 and 2025.<sup>396</sup> DTE argues that the current historical, bridge, and projected test period underlying the current case presents a more than sufficient estimate of the investments DTE needs to make to secure the integrity of its system.<sup>397</sup>

This PFD agrees with DTE that ABATE's proposed disallowance is overly broad and unsupported. Thus, this PFD recommends that the Commission reject ABATE's proposed disallowance.

### **Infrastructure Recovery Mechanism (IRM)**

Mr. Janness states that the Infrastructure Recovery Mechanism (IRM) is the program name for a series of capital expenditures that support long-term improvements to DTE Gas's infrastructure.<sup>398</sup> He adds that three processes make up the IRM capital expenditures: Gas Renewal Program (GRP – formerly two separate programs, MRP and MMO), Meter Assembly Check Meter Move-Out (MAC/MMO) and Pipeline Integrity

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<sup>394</sup> Id.

<sup>395</sup> 4 Tr 1989-1990

<sup>396</sup> DTE initial brief, p. 46-47.

<sup>397</sup> Id., p. 47.

<sup>398</sup> 4 Tr 588. This PFD notes that a sub-title to Mr. Janness' testimony refers to the IRM as being descriptive of "Investment Recovery Mechanism". Id., line 1. However, Mr. Janness' previously referred to the IRM as descriptive of the Infrastructure Recovery Mechanism. 4 Tr 586.

(PI).<sup>399</sup> He states that DTE seeks to recover its cost related to IRM capital expenditures from January 2025 through 2029 using a new IRM surcharge.<sup>400</sup>

Mr. Janness states that the Gas Renewal Program (GRP) is a focused effort to upgrade DTE distribution system through replacement of legacy mains and the relocation of meters from the inside to the outside of customer homes and businesses.<sup>401</sup> He adds that GRP currently has a goal to replace 206 miles of legacy mains and move out 14,790 inside meters annually, with the program being on pace to conclude in 2035 upon elimination of all legacy mains and the moving outside of all feasibly possible inside meters.<sup>402</sup> He states that the MAC MMO program is a supplementary meter move-out effort that specifically targets and prioritizes relocation of inside meters that have an overdue MAC (Meter Assembly Check) inspection.<sup>403</sup>

Mr. Janness states that DTE Gas has reduced the backlog of inside meters with overdue MACs from 129,305, when the MAC MMO program was initiated in 2018, to 22,148 at the end of 2022.<sup>404</sup> He adds that DTE expects to be current with meter assembly checks by the end of 2024, eliminating the need to specifically target 8,000 inside meters on the MAC backlog list yearly past 2024.<sup>405</sup>

Mr. Janness states that DTE exceeded the IRM expenditure target in 2021 by \$19.9 million and in 2022 by \$27.7 million.<sup>406</sup> He adds that DTE's total IRP proposed Capital Expenditures through 2029 are: 2023 - \$336.1 million; 2024 - \$349.1 million; 2025

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<sup>399</sup> Id.

<sup>400</sup> Id.

<sup>401</sup> 4 Tr 589.

<sup>402</sup> Id.

<sup>403</sup> 4 Tr 589-590.

<sup>404</sup> 4 Tr 590.

<sup>405</sup> Id.; Ex. A-12, Sch. B6.2.

<sup>406</sup> 4 Tr 591.

- \$354.2 million; 2026-2027 - \$344.5 million; 2028-2029 - \$311.4 million.<sup>407</sup> He states that DTE is projecting additional costs to execute the Main Renewal Program in both the Southeast and Greater Michigan service territories from 2020 through 2025, with three primary drivers of this cost increase: Increasing contractor and material costs; Municipal permit requirements for design, third party inspection, temporary and final restoration, as well as flowable fill; and A change in the scale and scope of projects as identified by the Probabilistic Risk Assessment.<sup>408</sup>

Mr. Janness states that Pipeline integrity is the program used by DTE to manage and ensure the integrity of the gas transmission system as prescribed in Subpart O of the Michigan Gas Safety Standards (MGSS), Pipeline Integrity Management.<sup>409</sup> He adds that In-Line-Inspection (ILI) involves inserting an electronic instrumented module into the pipeline at one end and typically propelling it to the other end utilizing the velocity of the gas, while recording metal loss data and other information about the pipeline.<sup>410</sup> He states that ILI Expansion is the program implemented by DTE to increase the coverage of transmission integrity assessments beyond the minimum requirements specified in MGSS, Subpart O, Pipeline Integrity Management.<sup>411</sup> He asserts that from 2023 through 2025, DTE ILI expansion plan includes retrofit of an additional 276 miles of pipeline for inspection by ILI, increasing coverage of the total transmission system assessable by ILI from 66.8% in 2022 to 83.6% in 2025.<sup>412</sup>

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<sup>407</sup> 4 Tr 592, Table 1.

<sup>408</sup> 4 Tr 593.

<sup>409</sup> 4 Tr 611.

<sup>410</sup> 4 Tr 613.

<sup>411</sup> 4 Tr 613-614.

<sup>412</sup> 4 Tr 615.

Mr. Janness states that from December 31, 2022, the end of the historical test year, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$50.0 million of PI capital expenditures.<sup>413</sup> He adds that DTE is changing the IRM surcharge, which will commence January 1, 2025, will be based on PI spending for 2024, with both IRM and expenditures in excess of IRM to total \$22.3 million.<sup>414</sup>

Mr. Coppola states that the Attorney General asked DTE to provide the current phase of development for four large ILI projects shown on Exhibit A-12, Schedule B5.5 and in response, DTE reported that three of the four projects -- Muskegon-Ludington 10 Scott Tie-in, the Belle River Field Headers 12 &16, and the Belle River Field Header 24 - - are currently in the conceptual design phase.<sup>415</sup> He adds that the forecasted amount for the three projects for the 9 months ending September 2024 is \$3,588,000 and \$8,576,000 for the 12 months ending September 2025.<sup>416</sup> He asserts that these projects are still in the early phase of development with no assured timeline and thus it is premature to include in rate base in this rate case.<sup>417</sup> Thus, he recommends that the Commission disallow \$3,588,000 of capital expenditures for the 9 months ending September 2024 and \$8,576,000 for the projected test year.<sup>418</sup>

Mr. Janness counters that these programs have an assured timeline, as DTE Gas is utilizing a two-year project cycle for capital projects, including ILI projects, with engineering to be completed in year 1 and construction in year 2.<sup>419</sup> He adds that the

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<sup>413</sup> 4 Tr 623; Ex. A-12, Sch. B5.3.

<sup>414</sup> 4 Tr 624.

<sup>415</sup> 4 Tr 1463; Ex. AG-15.

<sup>416</sup> Id. Citation omitted.

<sup>417</sup> 4 Tr 1463.

<sup>418</sup> Id.

<sup>419</sup> 4 Tr 641.

timing for these ILI projects will be project engineering having occurred in 2023 or occurring in 2024, and construction occurring during the 2024 or 2025 construction season.<sup>420</sup> He adds that this construction timeline aligns with the projected test year.<sup>421</sup> Mr. Janness notes that DTE's discovery response erroneously indicated that the current phase was "Conceptual Design" when all of the projects except one were in the engineering phase of the project.<sup>422</sup>

Ms. Creisher states that while Staff generally supports DTE's proposed work related to the In-Line Inspection (ILI) Expansion program, Staff does not support DTE's proposed level of capital expenditure related to the ILI Expansion program.<sup>423</sup> She asserts that DTE's audit responses show that a) DTE identified three projects that do not have ILI assessment requirements pursuant to Subpart O of Part 192 or 49 CFR 192.710 (Belle River Headers (12) and (16), Belle River Header (24), and Lincoln-Traverse City (12) projects), b) DTE identified that it will not actually utilize the ILI capability for several projects as much as three to five years after construction is completed; and c) DTE proposes to complete construction of four additional ILI expansion projects by October 2025 with similar delays in assessment.<sup>424</sup> She adds that while Staff recognizes that ILI assessments are an effective method of assessment to ensure the safety and reliability of the transmission system and that the complexity and need for flexibility in construction of the ILI Expansion projects, Staff finds that the proposed pace and timing of DTE's ILI

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<sup>420</sup> 4 Tr 642.

<sup>421</sup> Id.

<sup>422</sup> Id.

<sup>423</sup> 4 Tr 1794, 1795.

<sup>424</sup> Id.

Expansion projects is not reasonable and prudent at this time, and that Staff is generally supportive of construction of the ILI Expansion projects two years prior to the targeted assessment date unless further justification of advanced construction schedule can be provided.<sup>425</sup>

Ms. Creisher states that Staff proposes that the capital expenditures for the Belle River Headers (12) and (16) project should not be allowed for recovery in base rates at this time, such that Staff recommends capital expenditures of \$3,700,000 in the nine months ending September 30, 2024, and \$1,100,000 in the test year ending September 30, 2025 should be removed from DTE's total capital expenditures for the Pipeline Integrity Program.<sup>426</sup> In addition, she states that Staff recommends that DTE should adjust its ILI Expansion projects and Pipeline Integrity capital expenditures to a consistent level over the IRM, such that Staff recommends DTE should be allowed Pipeline Integrity program capital expenditures of \$13,400,000 in the IRM for 2025 through 2029.<sup>427</sup>

This PFD agrees with Staff's proposed disallowances while noting that Staff's proposed disallowances appear to be somewhat duplicative, albeit lesser in amount, of the disallowances sought by the Attorney General. Thus, this PFD recommends that the Commission accept Staff's proposed disallowances and to avoid duplication reject the Attorney General's proposed disallowances.

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<sup>425</sup> 4 Tr 1796.

<sup>426</sup> 4 Tr 1796-1797; Ex. S-10.0.

<sup>427</sup> 4 Tr 1797; Ex. S-10.1.

Mr. Janness states that cathodic protection is installed on the metallic components of DTE's gas infrastructure to protect it from external, internal, and atmospheric corrosion.<sup>428</sup> He states that as of 2022, approximately 25% of DTE's gas distribution system is cathodically protected steel and is not included in the scope of the GRP for replacement by 2035.<sup>429</sup>

Mr. Janness states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE will have incurred \$23.7 million of cathodic protection capital expenditures.<sup>430</sup> He adds that on average, DTE expects 2023-2025 cathodic protection capital expenditures to be \$3 million higher per year than the 2020-2022 \$5.6 million three-year average.<sup>431</sup> He states that the increase is related to the unit-based work, as on average, corrosion work order unit costs have increased from \$3,056 per unit in 2020 to \$4,624 in 2023, with DTE forecasting a unit cost of \$4,012 for 2024-2029.<sup>432</sup> He adds that DTE forecasts 1,695 Corrosion Work Orders per year starting in 2024 based on a 4-year historical average of units completed 2020-2023.<sup>433</sup> He states that if cathodic protection capital expenditures are not approved to be included in the IRM, these costs must be included in routine capital plant expenditures as they were in case no. U-20940.<sup>434</sup>

Mr. Coppola argues the increasing cost trend of the IRM is not sustainable from a customer affordability viewpoint and must be reversed.<sup>435</sup> He asserts that the Commission

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<sup>428</sup> 4 Tr 627.

<sup>429</sup> 4 Tr 628.

<sup>430</sup> 4 Tr 629; Ex. A-12, sch. B5.1.

<sup>431</sup> Id., Table 10.

<sup>432</sup> 4 Tr 630.

<sup>433</sup> Id.

<sup>434</sup> 4 Tr 632.

<sup>435</sup> 4 Tr 1457.

should set a maximum spending level or a cap for the IRM and the related component programs to avoid the current runaway cost.<sup>436</sup> He states that in response to discovery DTE provided a schedule that shows the capital spending on each of the programs included within the IRM from 2018 to 2029 with related quantity of work units.<sup>437</sup> He adds that based on the actual spending of \$240 million in 2021, DTE retired 214 miles of legacy mains and replaced them with 252 miles of new main under the MRP and that during 2021, DTE also replaced 25,967 services as part of the MRP.<sup>438</sup>

Mr. Coppola recommend that the Commission approve a maximum capital spending level of \$240 million for the MRP within the IRM instead of the \$274 million proposed by DTE for 2025, chosing 2021 as the benchmark year because it was the last year when spending on the MRP was still below \$250 million and DTE was able to retire more than 200 miles of legacy mains.<sup>439</sup> He adds that for 2024 through 2029, DTE's forecast is to retire 206 miles of legacy mains, albeit at a higher cost per mile.<sup>440</sup>

Mr. Coppola states that in total, for the MMO programs, DTE spent \$48.2 million in 2021 and forecasted to spend approximately \$47.5 million in 2025.<sup>441</sup> He recommends that the Commission approve inclusion of \$48 million in capital expenditures in the IRM for 2025 for the combined MMO programs.<sup>442</sup> He notes that for Pipeline Integrity, DTE spent \$11.7 million in 2021 and forecasted to increase spending on this program to \$23 million in the IRM for 2025.<sup>443</sup>

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<sup>436</sup> Id.

<sup>437</sup> 4 Tr 1458.

<sup>438</sup> Id.; Ex. AG-12.

<sup>439</sup> Id.

<sup>440</sup> Id.

<sup>441</sup> Id.

<sup>442</sup> Id.

<sup>443</sup> Id.

Noting that DTE plans to accelerate spending in this area to meet its goal of completing 97% of the total HCA assessments by 2025, Mr. Coppola asserts that the assessments should be stretched over a longer period as no compelling reason has been provided by DTE that the 97% goal must be achieved in 2025.<sup>444</sup> He states that DTE's capital expenditures forecast for Pipeline Integrity from 2025 to 2029 total to \$72.1 million, which average to \$14.4 million annually over the five-year period.<sup>445</sup> Thus, he recommends that capital expenditures for this program under the IRM for 2025 be set at no higher than \$15 million.<sup>446</sup>

Mr. Coppola concludes that in total he recommends that the Commission approve a spending level of \$303 million for the IRM for 2025 and allow the Company to increase that amount by an inflation factor of 2.5% annually beginning in 2026 and in subsequent years.<sup>447</sup>

DTE disagrees with the claim that it is expanding the IRM too quickly.<sup>448</sup> DTE asserts that the Commission has been exceedingly clear that the obligation to assure safe and reliable utility service is paramount and of critical importance, which includes eliminating cast iron and other poor-performing mains and eliminating inside meters – the core objectives of the IRM programs.<sup>449</sup> DTE notes that in Case No. U-18999, the Commission ordered an expansion of the MRP scope on the basis that rapid replacement and retirement of poor-performing and unprotected mains would stabilize the distribution

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<sup>444</sup> 4 Tr 1459.

<sup>445</sup> Id.

<sup>446</sup> Id.

<sup>447</sup> Id.

<sup>448</sup> DTE initial brief, p. 55-56.

<sup>449</sup> DTE initial brief, p. 55-56.

system and reduce the threat of major failure.<sup>450</sup> DTE asserts that its proposed schedule for construction and expenditures appropriately balances the need to eliminate these items and the outlay of capital expenditures required to perform the corresponding work.<sup>451</sup> DTE argues that approval of expenditures at Mr. Coppola's levels would result in a substantial setback to the legacy retirement pace and jeopardize DTE's ability to fully stabilize the distribution system and reduce the threat of major failure.<sup>452</sup> DTE asserts that the spending levels requested by DTE Gas are reasonable and justified, and that Mr. Coppola's recommendations to cap the IRM surcharge undermine the structure this Commission saw fit to impose on DTE to appropriately commit to completing important safety work.<sup>453</sup>

This PFD agrees with DTE. While Mr. Coppola's concerns about affordability are well-taken, his proposed broad, top-down approach to cap costs regardless of consideration of the reasonableness of the specific expenditures or the context within which the expenditures were requested and made is itself an unreasonable approach. Moreover, DTE's proposed expenditures are consistent with the policy considerations previously emphasized by the Commission. Thus, this PFD recommends that the Attorney General's proposed disallowance be rejected.

Separately, Mr. Coppola disagrees with DTE's proposal to include cathodic protection capital expenditures in the IRM, asserting that DTE has not provided any compelling reasons why cathodic protection costs need to be included in the IRM.<sup>454</sup> He

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<sup>450</sup> Id., p. 56.

<sup>451</sup> Id.

<sup>452</sup> Id.

<sup>453</sup> Id.

<sup>454</sup> 4 Tr 1460.

states that the reasons DTE offers to include the cathodic protection program within the IRM, such as assurance that the expenditures would be reasonable and prudent and that sufficient expenditures will be dedicated to cathodic protection, apply whether the capital expenditures are in base rates or in the IRM.<sup>455</sup> He asserts that DTE should make prudent spending decisions irrespective of how cost recovery occurs and should allocate sufficient resources to the program irrespective of the cost recovery methodology.<sup>456</sup> He adds that, as to formalizing a holistic and programmatic approach to cathodic protection, the Attorney General asked DTE to explain what such a program would look like and why it could not be done also with cost recovery in base rates, and that in response, DTE states that it had not determined yet that cathodic protection cannot continue to be included in bases rates, but seems to prefer the automatic cost recovery through the IRM.<sup>457</sup> He concludes that DTE has not made a convincing case that capital expenditures for cathodic protection should be included in the IRM, and thus, he recommends that the Commission reject DTE's proposal and instead add \$7,400,000 of cathodic protection costs to the \$2,200,000 already included the projected test year for a total amount of \$9,600,000.<sup>458</sup>

Mr. Janness counters that Cathodic Protection is appropriate to be included in the IRM because it is a strategic capital improvement and the IRM will ensure the dollars included in rates will be spent for this purpose as well as provide greater long-term certainty on recovery of these reasonable and prudent costs.<sup>459</sup> Mr. Janness states that by including these expenditures within the scope of the IRM, DTE can assure its

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<sup>455</sup> Id.

<sup>456</sup> Id.

<sup>457</sup> Id.; Ex. AG-13.

<sup>458</sup> 4 Tr 1461.

<sup>459</sup> 4 Tr 640.

customers and Staff that these expenditures are reasonable with increased transparency to costs, unit completions, and projects; that the minimum expenditure levels are dedicated to cathodic protection through 2029; and of the reduction of gas leaks.<sup>460</sup> He adds that Cathodic Protection is an integral part of Pipeline Integrity which is already part of IRM.<sup>461</sup>

This PFD agrees with the Attorney General that the reasons DTE offers to include the cathodic protection program within the IRM apply whether the capital expenditures are in base rates or in the IRM. This PFD also agrees that DTE should make prudent spending decisions irrespective of how cost recovery occurs and should allocate sufficient resources to the program irrespective of the cost recovery methodology. Moreover, this PFD notes that DTE admits that it had not determined yet that cathodic protection cannot continue to be included in bases rates. Thus, this PFD recommends that the Commission adopts the Attorney General's recommendation to reject DTE's proposal and instead add \$7,400,000 of cathodic protection costs to the \$2,200,000 already included the projected test year for a total amount of \$9,600,000.

Ms. Napoleon states that DTE Gas's current IRM allowed DTE to recover the predetermined incremental revenue requirement for annual infrastructure capital expenditures in certain programs for each year from 2022 to 2026.<sup>462</sup> She asserts that it is unclear how DTE determines which programs are appropriate for inclusion in the IRM, with DTE claiming that all of the programs currently included within the IRM are essential

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<sup>460</sup> Id.

<sup>461</sup> 4 Tr 641.

<sup>462</sup> 4 Tr 889-900.

to ensure safety and reliability but noting that there are many other programs that DTE determines to be essential for safety and reliability that are not included in the IRM.<sup>463</sup>

Ms. Napoleon states that the 2022 annual budget is \$287 million, which is about 370 percent of the initial IRM annual budget, with much of the increase in IRM budgets occurring over the past seven years, during which time the annual budget for IRM programs has more than tripled.<sup>464</sup> She adds that DTE has overspent its IRM annual budget by as much as \$50 million per year, while noting that expenditures on IRM programs that exceed the authorized IRM spending amounts are included in rate base in the next rate case.<sup>465</sup>

Ms. Napoleon states that the IRM is a channel for DTE to make infrastructure investments in a way that is low risk to the utility, because spending on the IRM is pre-approved.<sup>466</sup> She asserts that the IRM poses several issues:

As implemented, the IRM fails to provide adequate incentives for the utility to minimize costs.

Budget and actual spending on IRM programs has increased substantially since the IRM was first approved, and DTE's IRM expenditures have consistently exceeded budget.

The IRM process lacks meaningful external review and opportunity for contestation.

The criteria for what types of projects qualify for the IRM are unclear, and the utility has incentives to include routine projects in the IRM. The IRM includes minimal guardrails.

Over three-quarters of the proposed IRM expenditure is for replacing old pipes (which may or may not be leak-prone). DTE doesn't pursue alternatives to conventional delivery system investments (NPAs), which could reduce

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<sup>463</sup> 4 Tr 900.

<sup>464</sup> 4 Tr 900-901, Table 1.

<sup>465</sup> 4 Tr 901-902. Citation omitted.

<sup>466</sup> 4 Tr 904.

investments and impacts on rates. The IRM provides no oversight over decisions to replace old pipes rather than evaluate and pursue NPAs.<sup>467</sup>

Ms. Napoleon states that DTE has not conducted a benefit-cost analysis to determine the cost effectiveness of the Gas Renewal Program, the Meter Move Out Program, or the Pipeline Integrity program.<sup>468</sup> She asserts that to the extent there are alternatives to these programs, such as emissions monitoring and pipe repair, an assessment of the cost-effectiveness of these programs relative to the alternatives is a necessary step to understanding and minimizing costs.<sup>469</sup> Noting that DTE's IRM spending has consistently exceeded its budget and that DTE's actual cost per unit has been higher than projected most years from 2016 to 2022, she argues that the overall pattern gives rise to concerns that DTE's spending on investments not subject to normal rate case review has been high and that there is a lack of oversight of its spending.<sup>470</sup>

Ms. Napoleon asserts that DTE may be applying the vague criteria for qualifying projects for the IRM liberally to proposed investments that are part-and-parcel of a gas utility's business and do not reasonably warrant special treatment.<sup>471</sup> She adds that qualifying projects for the IRM reduces DTE's risk that the project could be found imprudent in the future.<sup>472</sup>

Ms. Napoleon states that there may also be cost recovery advantages of passing investments through the IRM, noting that the currently-approved pre-tax rate of return used to calculate the IRM tariff rates is 8.78%, while DTE Gas' currently approved overall

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<sup>467</sup> 4 Tr 905.

<sup>468</sup> 4 Tr 906-907; Ex. MEC-30.

<sup>469</sup> 4 Tr 907.

<sup>470</sup> 4 Tr 906-907.

<sup>471</sup> 4 Tr 908.

<sup>472</sup> Id.

required rate of return (for investments recovered through base rates) is 5.41 after taxes.<sup>473</sup> She adds that for this case, DTE proposes a pre-tax rate of return of 9.31% to calculate the IRM revenue requirement, while the proposed overall after-tax rate of return for non-IRM investments is 6.04%.<sup>474</sup>

Ms. Napoleon states that DTE done analysis on whether it would be cheaper for ratepayers to remove pipe from service without replacing it, rather than replace it, as DTE does not evaluate let alone pursue non-pipeline alternatives (NPA).<sup>475</sup> She adds that DTE has not identified assets or types of assets on its gas system that may be most or least likely to remain used and useful in the event of widespread electrification of gas end uses.<sup>476</sup>

Ms. Napoleon states that gas system assets, including those in the IRM, have very long physical engineering lifetimes, and that in light of the market and policy developments that will put downward pressure on gas sales, utilities will seek to recover the costs of gas system assets over fewer sales, pushing up gas prices.<sup>477</sup> She asserts that, in turn, reductions in load and customer defection from the gas system would escalate costs for remaining customers, which may cause some gas assets to become underutilized or no longer serve customers and become stranded.<sup>478</sup>

Ms. Napoleon recommends that the Commission not approve the proposed IRM and instead, the Commission should initiate an open, collaborative proceeding to consider

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<sup>473</sup> 4 Tr 909. Citation omitted.

<sup>474</sup> Id.

<sup>475</sup> 4 Tr 911.

<sup>476</sup> Id.; Ex. MEC-22.

<sup>477</sup> 4 Tr 914.

<sup>478</sup> Id.

and revise the purpose, requirements, process, and structure of the IRM.<sup>479</sup> She adds that through the IRM or otherwise, any investment in pipeline replacements should be evaluated against gas demand projections as well as NPAs.<sup>480</sup> She asserts that the Commission should not approve increases in IRM spending or expansion of its scope in this rate case.<sup>481</sup>

Regarding Ms. Napoleon's recommendation for more stringent guidelines for the IRM eligibility, Mr. Janness states that the investments included in the IRM are strategic capital improvements, and that the IRM ensures that the spending on these capital improvements is made a priority.<sup>482</sup> Regarding Ms. Napoleon's recommendation to not approve the IRM, but instead to have open collaborative proceedings to consider and revise purpose, requirements, process and structure, Mr. Janness counters that rate cases, including prior rate cases, are an open collaborative opportunity for the IRM.<sup>483</sup>

Regarding Ms. Napoleon's recommendation that the expansion of IRM scope and/or spending not be approved, Mr. Janness states that her claims that the IRM provides a reduced incentive to minimize costs while noting that the IRM budget has been increasing over the past seven 7 years, Mr. Janness states that the cost per legacy mile retired has remained within 7% of the 2020 cost, even as complexity and restoration requirements have increased, and that if its expenditures exceed the amounts used to calculate the IRM surcharge, DTE carries the cost of those amounts until the next rate case.<sup>484</sup> He adds that the purpose of the IRM is to ensure spending on these capital

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<sup>479</sup> 4 Tr 914.

<sup>480</sup> 4 Tr 914-915.

<sup>481</sup> 4 Tr 915.

<sup>482</sup> 4 Tr 643.

<sup>483</sup> 4 Tr 644.

<sup>484</sup> 4 Tr 645.

improvements is a priority and that DTE is requesting an increase in the annual amount included in the surcharge as the work becomes more complex and market and inflation pressures increase costs.<sup>485</sup> Regarding Ms. Napoleon's recommendation to require that all investments be evaluated against non-pipeline alternatives (NPAs), Mr. Janness states that DTE is committed to providing cost-effective options for customers to manage their own fuel use, and since the goal of the GRP is to replace leak prone pipe, energy efficiency or demand response would not change the need for that investment.<sup>486</sup>

This PFD agrees with DTE regarding most of Ms. Napoleon's recommendations for the reasons offered by DTE. However, like with respect to Mr. Coppola's recommendation, this PFD agrees that the Commission should reject DTE's proposal to include cathodic protection capital expenditures in the IRM.

#### **Non-IRM Capital Expenditure Programs**

Regarding meter move-out, Mr. Janness states that as of January 2023, DTE has an inside meter balance of 148,403 putting DTE's 3,143 inside meters ahead of the forecast established in U-20940.<sup>487</sup> He adds that DTE completed 72,854 meter move-outs between 2020 and 2022 compared to the forecast of 81,970, and that over this period, IRM programs exceeded the inside meter move-out goal by 3,533, while routine meter move-out completions were 9,016 less than forecasted.<sup>488</sup> He states that DTE estimates it will complete both legacy main renewal and inside meter move-out by 2035.<sup>489</sup> He adds that with the current approved IRM capital expenditures and dedicated

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<sup>485</sup> 4 Tr 645-646.

<sup>486</sup> 4 Tr 646.

<sup>487</sup> 4 Tr 599.

<sup>488</sup> 4 Tr 599-600, Table 5; Ex. A-12, Sch. B6.2.

<sup>489</sup> 4 Tr 602.

resource levels, DTE proposes to move out all feasible inside meters on non-legacy mains in Southeast Michigan by the end of 2028, leaving only 3% of total DTE gas meters inside by that point.<sup>490</sup>

Regarding main replacement, Mr. Janness states that DTE Gas is proposing to use a single “grid-based” risk prioritization model in lieu of selecting projects from separate segment and grid rankings, eliminating the yearly goal of replacing 15 miles of “risk ranked” segments.<sup>491</sup> He adds that DTE is proposing to continue the practice of pulling forward select segments of legacy main renewal for a few reasons, including: municipal coordination, field recommended, and corrosion recommended.<sup>492</sup> He states that at the beginning of 2024 (the start of full PRA implementation), DTE estimates that it will have about 2,285 miles of legacy main, such that in the 12 years 2024-2035, DTE needs to retire an average of 190 miles of main each year to meet the 18-year pace approved in Case No. U-18999.<sup>493</sup> He adds that DTE maintains that a degree of flexibility in yearly main and inside meter unit goals is necessary and prudent to maintain the accelerated pace of the Gas Renewal Program.<sup>494</sup> He states that DTE is proposing a yearly ‘minimum goal’ mileage of 190 miles for GRP, allowing DTE to perform fewer miles annually than the 206 miles approved in Case No. U-20940.<sup>495</sup> He adds that with this strategy, DTE Gas can ensure relatively consistent capital expenditure levels and dedicated resources in defined geographic areas.<sup>496</sup>

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<sup>490</sup> 4 Tr 603.

<sup>491</sup> 4 Tr 606.

<sup>492</sup> 4 Tr 607.

<sup>493</sup> 4 Tr 609.

<sup>494</sup> Id.

<sup>495</sup> Id.

<sup>496</sup> 4 Tr 610.

Mr. Fitzhenry states that the Main Replacement Program capital expenditures made up a significant portion of DTE's historical distribution plant investment, and as a result, caused significant increases in DTE's rate base.<sup>497</sup> He asserts that DTE does not require its proposed level of capital expenditures for its main replacement program to ensure safety and reliability, adding that DTE was able to demonstrate it could make system improvements through its Main Replacement Program prior to the elevated level of investment incurred in 2022, and that DTE only needs to retire an average of 190 miles of main each year to meet the 18-year pace approved in Case No. U-18999, which is less than the 206 miles being proposed by DTE.<sup>498</sup> Thus, he recommends that DTE adjust the rate of main replacements in order to reduce the impact of capital expenditures on customers' rates.<sup>499</sup> He asserts that DTE can still remain on pace with the approved target miles in Case No. U-18999 by replacing 16 less miles of main per year, which would reduce the Main Replacement Program capital expenditures by approximately \$62 million.<sup>500</sup>

DTE counters that Mr. Fitzhenry's proposed reduction in expenditures fails to take into account the increased costs associated with more complex grids selected using the results of DTE's Probabilistic Risk Assessment, with the grids being estimated to increase costs by 20 to 30% from 2022 levels.<sup>501</sup> DTE asserts that the grids are more complex and require additional costs, such that DTE needs the flexibility to replace as few as 190 miles annually without a reduction in expenditures.<sup>502</sup>

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<sup>497</sup> 4 Tr 1316.

<sup>498</sup> 4 Tr 1317. Citation omitted.

<sup>499</sup> 4 Tr 1318.

<sup>500</sup> Id.

<sup>501</sup> DTE initial brief, p. 61.

<sup>502</sup> Id.

This PFD agrees with ABATE, which proposes that DTE limit its average retirement of 190 miles of main each year to meet the 18-year pace approved in Case No. U-18999, which matches DTE's yearly minimum goal mileage of 190 miles for GRP. Moreover, while DTE argues that it needs the flexibility to replace as few as 190 miles annually without a reduction in expenditures, DTE asserts that with its proposed strategy, DTE can "ensure relatively consistent capital expenditure levels." Thus, this PFD recommends that the Commission adopt ABATE's disallowance of the Main Replacement Program capital expenditures by approximately \$62 million.

Ann Arbor requests that the Commission should put DTE on notice that it will consider costs to be imprudently incurred if DTE has failed to review publicly available Capital Improvement Plans (CIPs) to identify opportunities for cost savings for non-emergency projects.<sup>503</sup> Dr. Stults asserts that this lack of coordination – which she asserts should require review of publicly available CIPs -- likely creates waste throughout DTE's service territory, which in turn drives up rates.<sup>504</sup> She adds that if DTE employees focus on reducing costs by identifying coordination opportunities years in advance (when it is easiest to align schedules), it should be possible to capture the savings from increased coordination without an increase in headcount, and achieve an overall decrease in rates.<sup>505</sup> In that regard, Dr. Stults states that the Commission should require DTE in its next rate case to report on systematic changes it has made to coordinate its infrastructure projects with other utilities and local governments in an effort to reduce costs and disruptions.<sup>506</sup>

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<sup>503</sup> 3 Tr 508-509.

<sup>504</sup> 3 Tr 525.

<sup>505</sup> 3 Tr 525-526.

<sup>506</sup> 3 Tr 509.

DTE replies that it supports work coordination and strives to achieve it where possible but disagrees that costs should be excluded from recovery if work coordination does not occur, arguing that it would be inappropriate to prioritize work coordination with the city ahead of strategically scheduled work sequencing or regulatory requirements with firm timelines.<sup>507</sup> DTE asserts that it has met with representatives of the City of Ann Arbor, provided timelines and maps of planned GRP work for 2024 and 2025, and designated a dedicated Regional Relations employee to be a resource and point of contact to address DTE Gas's plans and any concerns Ann Arbor may have.<sup>508</sup> As such, DTE argues that the Commission should reject Ann Arbor's calls for a report of improved coordination efforts as duplicative of work already being done.<sup>509</sup>

This PFD agrees with DTE. DTE need not be put on notice that the Commission might consider costs to be imprudently incurred if DTE has failed to take advantage of opportunities for cost savings; every utility regulated by the Commission is aware of that from the Commission's prior orders. Similarly, DTE should not be required to report on systematic changes it has made to coordinate its infrastructure projects with other utilities and local governments in an effort to reduce costs and disruptions, as Ann Arbor has not demonstrated that any such systemic changes are required. Indeed, DTE has shown that it has engaged in improved communication and coordination efforts with Ann Arbor.

Dr. Stults states that the expenditures for six distribution pipeline replacement projects in Ann Arbor are not reasonable and prudent because the majority of the main pipelines replaced or planned to be replaced under these projects were or are coated

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<sup>507</sup> DTE initial brief, p. 62.

<sup>508</sup> Id.

<sup>509</sup> Id.

steel or plastic pipelines with little to no history of leak repairs.<sup>510</sup> Based on the testimony of Mr. Ackley, she asserts that pipelines made of these materials should be able to safely operate until at least 2050 – the date Ann Arbor forecasts that it will no longer require fossil gas service -- as long as they are monitored for leaks and repaired as necessary.<sup>511</sup> She adds that Mr. Ackley estimated the cost to repair all of the gas leaks he detected on DTE’s system in Ann Arbor to be approximately \$825,000.<sup>512</sup> She states that the total cost for all the Ann Arbor projects is \$20,420,354.<sup>513</sup> She argues that investing over \$20 million in new infrastructure for only a portion of the City, when DTE could instead fix all the leaks in Ann Arbor for less than a million dollars is not reasonable or prudent, but rather a waste of ratepayer dollars that only serves to grow DTE’s rate base, which leads to larger shareholder returns, even higher rates, and increases the risk of stranded assets.<sup>514</sup> Thus, she asserts that DTE should be denied recovery for the full amount of these unnecessary projects, and the dollars associated with them should not be included in DTE’s revenue requirement.<sup>515</sup>

Mr. Janness counters that Ann Arbor Muni is a portion of a grid planned for 2025/2026 that was pulled ahead into our 2024 plans to coordinate with the city of Ann Arbor due to road resurfacing the city has planned.<sup>516</sup> He adds that the segment of Ann Arbor Muni in question is entirely coated steel that is not cathodically protected, without which the coating can fail and corrode.<sup>517</sup> He states that in instances where DTE replaced

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<sup>510</sup> 3 Tr 524.

<sup>511</sup> 3 Tr 523, 524.

<sup>512</sup> 3 Tr 524.

<sup>513</sup> Id.

<sup>514</sup> Id.

<sup>515</sup> Id.

<sup>516</sup> 4 Tr 651.

<sup>517</sup> Id.

protected coated steel or plastic, it was done to raise the grid's operating pressure which improves the reliability of the system.<sup>518</sup> He adds that the remaining listed projects are public improvement projects which were initiated to resolve a utility conflict in coordination with the city of Ann Arbor.<sup>519</sup> DTE asserts that DTE Gas's work in the Ann Arbor area is consistent with the Commission's approved programs, such that the expenditures spent to achieve a safer, more reliable distribution system for Ann Arbor merit cost recovery in this case.<sup>520</sup>

This PFD agrees with DTE, which has demonstrated that these expenditures were reasonable and prudent. Thus, this PFD recommends that the Commission reject Ann Arbor's proposed disallowance.

MNSC asserts that the Commission should disallow a portion of the projected expenditures for two community expansion projects – Mesick-Buckley and Peach Ridge – because DTE has based the new customer contributions for those projects on wholly unrealistic subscription levels.<sup>521</sup> Dr. Hopkins states that DTE expects to spend about \$17 million more on new market attachments in 2023- 2025 than the recent five-year average and that for the period of 2023-2025, new market attachments will include two Community Expansion Projects (CEPs): the Mesick-Buckley Area Expansion Project (AEP) and Peach Ridge AEP.<sup>522</sup> Dr. Hopkins asserts that based on historical rates of customer attachments, the Mesick-Buckley expansion will have a deficit of about \$838,000 and the Peach Ridge expansion will have a deficit of about \$912,000.<sup>523</sup> He adds that DTE's past

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<sup>518</sup> Id.

<sup>519</sup> 4 Tr 652.

<sup>520</sup> DTE initial brief, p. 63.

<sup>521</sup> MNSC initial brief, p. 2, 32.

<sup>522</sup> MNSC initial brief, p. 11. Citations omitted.

<sup>523</sup> 4 Tr 830.

overestimates likely have an aggregate under-recovery of between \$6 million and \$11 million, and asserts that it is not just and reasonable to ask DTE's non-participating customers to pay these costs.<sup>524</sup>

Dr. Hopkins states that DTE provided information showing that across all community expansion projects, DTE appears to have overestimated customer connections by about 50 percent: that, for every 300 projected customers, DTE has connected only about 200.<sup>525</sup> He adds that on average, DTE appears to get about 80 percent as many customers as expected in Year 1, and by Year 3 (for projects that have been in operation that long), the ratio of actual to projected falls to about two-thirds.<sup>526</sup> He states that this means that DTE ratepayers not served by these expansion projects are paying a substantial net cost for these expansions, beyond what was projected when the projects were approved.<sup>527</sup>

Dr. Hopkins states that based on DTE's experience with customer attachment rates over the last few years, it is unreasonable for DTE to assume that all 1,063 identified customers will connect to the Mesick-Buckley project within five years, noting that none of the similar-sized projects from the last few years have approached 100 percent participation over five years.<sup>528</sup>

Dr. Hopkins states that DTE projects miscellaneous growth – which DTE states is a mechanism that allows additional new homes and businesses to be accounted for in the project calculations for the first 10 years of the project - of 2 percent per year, or about

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<sup>524</sup> Id.

<sup>525</sup> 4 Tr 869. Citation omitted.

<sup>526</sup> Id.

<sup>527</sup> Id.

<sup>528</sup> Id.

22 new customers per year, such that, as a result, by the end of the 20-year analysis window for the calculation of the revenue gap, DTE projects the project will serve more than 1,500 customers.<sup>529</sup> He adds that none of DTE's other projects with over 300 projected customers from the last few years include any assumed miscellaneous growth at all.<sup>530</sup>

Dr. Hopkins states if two-thirds of the projected customers sign up, without any additional miscellaneous growth, and DTE charges its projected amount for contributions in aid of construction, DTE will face a present-value shortfall of about \$838,000.<sup>531</sup> He adds that of this, a small (less than \$50,000) net shortfall would result in the first three years and thus may be borne by DTE investors (assuming DTE does not file another rate case within three years), while about \$800,000 present value of costs would be borne by DTE's ratepayers as a whole after the assets are all included in rate base at the next rate case.<sup>532</sup>

Dr. Hopkins states that he conducted a similar analysis of the Peach Ridge expansion project to what he did for Mesick-Buckley, estimating that DTE will likely experience a revenue deficiency with a present value of about \$912,000 if customer attachments for the Peach Ridge project proceed according to DTE's average experience of customer attachments to expansion projects.<sup>533</sup> He adds that under DTE's existing practice, this shortfall will be largely recovered from other DTE ratepayers who will see no benefit from the Peach Ridge project.<sup>534</sup>

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<sup>529</sup> 4 Tr 871; Ex. MEC-16. Citations omitted.

<sup>530</sup> Id.

<sup>531</sup> 4 Tr 872

<sup>532</sup> Id.

<sup>533</sup> 4 Tr 876.

<sup>534</sup> Id.

Dr. Hopkins recommends that if DTE cannot increase the required residential contributions in aid of construction (CIAC) surcharges, then the Commission should disallow inclusion in rate base of \$838,000 in new market attachments capital expenditures for the Mesick-Buckley CEP and \$912,000 for the Peach Ridge CEP.<sup>535</sup>

Mr. Abona counters that DTE is confident that existing homes will remain viable for more than 20 years, and that customers have the means and the choice to decide whether they prefer natural gas or electrification.<sup>536</sup> He adds that DTE along with five other utilities, adheres to guidelines that consider 20 years of revenue generated by the customer over a 20-year period as stated in the customer attachment program.<sup>537</sup>

This PFD agrees with MNSC, finding that DTE's projections for these projects are unrealistic and thus unreasonable. This PFD recommends that the Commission adopt MNSC's proposed disallowances.

### **Working Capital**

DTE's total rate base for the projected test year includes \$873 million of working capital.<sup>538</sup> The Attorney General proposes to reduce this working capital amount by \$10.1 million which adjustment pertains to the deferred Regulatory Asset-Incentive Tracker balance of \$13.3 million calculated by DTE.<sup>539</sup>

Mr. Coppola states that to arrive at the \$13.3 million balance, DTE added \$6,378,000 of expense to the \$1,057,000 incentive compensation expense approved by the Commission in Case U-20940, and that information provided in response to discovery

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<sup>535</sup> 4 Tr 879.

<sup>536</sup> 3 Tr 396.

<sup>537</sup> Id.

<sup>538</sup> 4 Tr 2357; Ex. A-12, Sch. B1.

<sup>539</sup> 4 Tr 1475; Ex. A-12, Sch. B4.

shows that the \$6,378,000 included in the deferred regulatory asset is a new calculated amount by DTE that does not conform to the amount requested by DTE in Case No. U-20940 for achieving 100% target level performance in 2022 for operating performance measures.<sup>540</sup> Noting that the amount forecasted by DTE in Case U-20940 was \$5,286,000, consisting of the sum of \$1,277,000 for the AIP and \$4,009,000 for the REP, and assuming DTE achieved all measures at 100% of target, Mr. Coppola states that the \$6,378,000 used by DTE is incorrect and should not be adopted by the Commission.<sup>541</sup>

Mr. Coppola states that the \$13.3 million working capital balance in the deferred compensation regulatory asset also included accruals that DTE has added for 2023, and 9 months of 2024, and thus, that the accruals for 2023 and 2024 are premature because DTE has not provided any evidence that it has achieved 100% of the operating target measures.<sup>542</sup> He adds that DTE seeks to recover only the amortization of the incremental amount of incentive compensation earned in 2022 in this rate case and the regulatory asset deferred amount should only reflect those incremental costs.<sup>543</sup>

Mr. Coppola states that he applied the percentage of actual performance achieved for the operational performance measures in each of the two incentive plans in 2022 to the amount of incentive payout at 100% of target, resulting in \$4,643,000 owed to DTE for 2022, which was the projected test year in Case No. U-20940.<sup>544</sup> He adds that this amount is \$3,586,000 higher than the \$1,057,000 that the Commission approved for inclusion in rates in Case No. U-20940 and is the only and proper amount that should be

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<sup>540</sup> 4 Tr 1475-1476; Ex. AG-54.

<sup>541</sup> 4 Tr 1476.

<sup>542</sup> Id.

<sup>543</sup> 4 Tr 1476-1477.

<sup>544</sup> 4 Tr 1477.

included in the regulatory asset and amortized over five years at an annual amount of \$717,000.<sup>545</sup> Thus, he concludes that the regulatory asset deferred balance that should be included in working capital is \$3,227,000, making DTE's working capital balance of \$13,310,000 overstated by \$10,083,000, and recommends that the Commission remove the \$10,083,000 from DTE's forecasted working balance amount for the projected test year.<sup>546</sup>

Noting that DTE proposes a three-year amortization period, Mr. Coppola states that customers are absorbing significant cost increases in other areas of this rate case and future rate cases to come, and would certainly appreciate a more gradual amortization period of at least five years.<sup>547</sup> He adds that it is preferable to amortize deferred balances over a longer time period to prevent cost over-recovery from occurring.<sup>548</sup> Thus, he recommend that the Commission approve an amortization period of five years with an amortization expense of \$717,000 in this rate case.<sup>549</sup>

Ms. Uzenski counters that Mr. Coppola's calculation contains two flaws. She states that Mr. Coppola used a forecast from the prior gas rate case instead of the actual expense incurred during 2022, noting that the mechanism design (like other similar tracker mechanisms) compares actual expense incurred to a pre-determined base amount.<sup>550</sup> Quoting from the Order in Case No. U-20940, p. 163, she adds that the correct

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<sup>545</sup> Id.

<sup>546</sup> Id.

<sup>547</sup> 4 Tr 1478.

<sup>548</sup> 4 Tr 1479.

<sup>549</sup> Id.

<sup>550</sup> 4 Tr 2336.

starting point for the calculation is actual 2022 incentive compensation expense related to operating metrics, capped at 100% of the target, which amount is \$6.378 million.<sup>551</sup>

Ms. Uzenski states that Mr. Coppola's second flaw is that he assumed performance results of 88.9% and 87.5%, which assumes all the operating metrics underlying the incentive compensation plan are equally weighted.<sup>552</sup> She adds that the results of the performance plan exceeded 100% on a weighted average basis, which weighted average is the basis for the incentive compensation plan.<sup>553</sup> She asserts that accordingly, the payout exceeded 100% and the amount eligible for deferral and recovery under the mechanism should be based on the 100% cap, which is \$6.378 million.<sup>554</sup> She states that a comparison of the correct amount for actual incentives achieved (capped at 100%) of \$6.378 million to the base results in the appropriate deferral amount of \$5.321 million, which is the amount that should be reflected in the regulatory asset for the initial deferral instead of the \$3.586 million proposed by Mr. Coppola.<sup>555</sup> She concludes that based on a three-year amortization period, the annual amortization expense is \$1.774 million.<sup>556</sup>

In its brief, DTE agrees to a \$4.0 million reduction in the deferred incentive compensation regulatory asset to reflect actual 2023 results.<sup>557</sup> DTE also agrees to a \$0.1 million reduction in working capital to adjust for a Treasury clearing account included in error.<sup>558</sup>

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<sup>551</sup> Id.; Ex. A-12, Sch. C5.6, p. 2.

<sup>552</sup> Id.

<sup>553</sup> 4 Tr 2336-2337; Ex. A-34, Ex. A-13, Sch. I2.

<sup>554</sup> 4 Tr 2337.

<sup>555</sup> Id.

<sup>556</sup> Id.; Ex. A-13, Sch. C5.6.

<sup>557</sup> DTE initial brief, p. 64.

<sup>558</sup> Id.

This PFD agrees with DTE that Mr. Coppola's calculation is mistaken, and that DTE's calculation should be used to assess this proposed expenditure. This PFD recognizes DTE's admission that the deferred incentive compensation regulatory asset should be reduced by \$4 million to reflect actual 2023 results, and that there should be a \$0.1 million reduction in working capital to adjust for a Treasury clearing account included in error. Thus, this PFD recommends that the Commission adopt these reductions as agreed to by DTE.

Mr. Hecht states that Staff presents a projected working capital of \$861,784,000, which is a decrease of \$11,096,000 from DTE's \$872,881,000 projection.<sup>559</sup> He adds that the \$11,096,000 difference is a combination of five adjustments made by Staff : first, Cash and Special Deposits, was reduced by \$136,000; second, Other Accounts Receivable, was reduced by \$300,000; third, Gas in Underground Storage, was reduced by \$9,133,000; fourth, Regulatory Assets – Shared Asset Deferral Mechanism, was reduced by \$1,304,000; and lastly, I/C Accounts Payable was increased by 223,000.<sup>560</sup>

Regarding the adjustment to reduce Cash and Special Deposits in the amount of \$136,000, Mr. Hecht states that DTE has acknowledged that the balance of \$136,000 included in the cash balance should be removed from working capital.<sup>561</sup> Regarding the adjustment to reduce Other Accounts Receivable in the amount of \$300,000, Mr. Hecht states that DTE has acknowledged that \$300,000 of the balance within other accounts receivable should be considered non-recoverable.<sup>562</sup> Regarding the adjustment to increase I/C Accounts Payable in the amount of \$223,000, Mr. Hecht states that DTE has

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<sup>559</sup> 4 Tr 1748; Ex. S-2, Sch. B4; Ex. A-12, Sch. B4.

<sup>560</sup> Id.

<sup>561</sup> Id.; Ex. S-12.2.

<sup>562</sup> 4 Tr 1748-1749; Ex. S-12.0.

acknowledged that for ratemaking purposes any netted receivable and payable balances from its trading partners included in working capital should only be related to core utility services netted against core utility services, and that that if all payables to affiliates are for core utility services, there should be an adjustment to increase inter-company accounts payable in the amount of \$223,000.<sup>563</sup>

Regarding gas in underground storage, Ms. Royal states that when DTE Gas developed its case, DTE used projected monthly costs and volumes from January 2023 through December 2025 to determine the 13-month average costs and volumes of natural gas in its underground storage reservoirs.<sup>564</sup> She adds that DTE Gas updated the monthly costs and volumes of natural gas in its underground storage reservoirs by incorporating the actuals from January through December 2023, and the projected monthly costs and volumes from January 2024 through December 2025 were updated using a five-day New York Mercantile Exchange (NYMEX) settlement average from February 12-16, 2024.<sup>565</sup> She states that Staff recommends that the 13-month September 2024 through September 2025 average cost of natural gas in underground storage reservoirs for GCR customers be decreased by \$9,133,000 to \$47,428,000.<sup>566</sup>

Noting that DTE does not appear to rebut Staff's evidence, this PFD agrees with Staff and recommends that the Commission adopt Staff's proposed disallowance.

Regarding the adjustment to reduce Regulatory Assets – Shared Asset in the amount of \$300,000, Ms. Rogers states that DTE's total Shared Asset Charge for the test period is \$50.83 million and that DTE is projecting an IT shared asset charge of \$38.6

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<sup>563</sup> 4 Tr 1749; Ex. S-12.1.

<sup>564</sup> 4 Tr 1808.

<sup>565</sup> 4 Tr 1808-1809.

<sup>566</sup> 4 Tr 1810; Ex. S-11.2.

million.<sup>567</sup> She adds that in Case No. U-21297, the Commission approved a shared asset revenue of \$57.4 million of which \$48.9 million is attributable to DTE Gas Company and that the total IT shared asset revenue approved by the Commission in U-21297 was \$41.7 million of which \$36.7 million is attributable to DTE Gas Company.<sup>568</sup> She notes that In Case No. U-21297, Staff recommended disallowances for IT projects that are shared between DTE Electric and DTE Gas Company and that DTE Electric Company argued that if those disallowances are approved by the Commission, the shared asset revenue should be reduced by \$1.9 million.<sup>569</sup> She states that Staff recommends a \$1.9 million adjustment to the IT shared asset charge so that the cost DTE Gas is paying DTE Electric for the use of the jointly beneficial IT programs/software/equipment matches the revenue that DTE Electric has been approved to collect per the Commission's order in U-21297, and that if DTE Gas paid the amount projected in the instant case, \$38.6 million, DTE Electric will gain an extra \$1.9 million that is unaccounted for, which would represent an unnecessary burden to DTE Gas ratepayers.<sup>570</sup> She adds that DTE Gas admits the reason for the discrepancy and states the shared asset charge should be lowered by \$1.9 million and that DTE updated its exhibit to reflect the change.<sup>571</sup> Based on Ms. Rogers' adjustment to reduce the O&M shared asset charge by \$1,931,000, Staff recommends reducing working capital by \$1,304,000.<sup>572</sup>

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<sup>567</sup> 4 Tr 1604, 1605; Ex. A-13, Sch. C5.6; Ex. S-13.4.

<sup>568</sup> 4 Tr 1605; Ex. S-13.4.

<sup>569</sup> 4 Tr 1605. Citation omitted.

<sup>570</sup> 4 Tr 1606.

<sup>571</sup> Id.; Ex. S-13.5, Ex. S-13.6.

<sup>572</sup> Staff initial brief, p. 9.

As DTE has agreed to or does not oppose these proposed changes, this PFD recommends that the Commission adopt Staff's proposed decrease of \$11,096,000 from DTE's working capital projections.

### **Depreciation Reserve**

Mr. Hecht states that Staff presents a projected depreciation reserve of \$2,750,769,000, which is a decrease of \$5,968,000 from DTE's \$2,756,737,000 projection.<sup>573</sup> He adds that the \$5,968,000 decrease is the result of a) depreciation adjustments using the currently approved depreciation rates from Case No. U-20118 results in decreasing the depreciation reserve by \$6,260,000 and b) the impact from Staff's capital expenditure adjustments.<sup>574</sup> Mr. Hecht states that an error was discovered in calculation of Staff's Depreciation Reserve adjustment total, the correction of which adjustment supported by Staff is a reduction to the depreciation reserve in the amount of \$6,552,000 (a \$6,260,000 reduction for currently approved depreciation rates and a \$292,000 reduction related to Staff's capital expenditure adjustments).<sup>575</sup>

Mr. Hecht states that DTE filed its rate case with rates that are currently not approved, but being sought for approval, in its Depreciation Case No. U-21384, and that Staff's adjustment uses the current approved depreciation rates from Case No. U-20118 at the time DTE made its rate case filing.<sup>576</sup> He states that Staff recommends that if an order is issued for Depreciation Case No. U-21384 prior to an order in the instant case, the Commission should implement the new ordered depreciation rates in the instant rate

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<sup>573</sup> 4 Tr 1747; Ex. S-2, Sch. B-1; Ex. A-12, Sch. B-1.

<sup>574</sup> Id.

<sup>575</sup> 4 Tr 1753-1754.

<sup>576</sup> 4 Tr 1751.

case, but that until Depreciation Case No. U-21384 is resolved, the currently approved rates from Case No. U-20118 should be used.<sup>577</sup>

This PFD agrees with Staff that the currently approved depreciation rates from Case No. U-20118 should be used until an order is issued in Case No. U-21384. The differences in depreciation reserve arise from the differences in capital expense amounts recommended by the parties. This depreciation reserve should be recalculated based on the determinations in the final order.

## V.

### **CAPITAL STRUCTURE AND RATE OF RETURN**

The capital structure used for ratemaking includes as its components long-term debt, preferred stock, and common equity capital – which are considered part of the utility’s “permanent capital” – and short-term debt and other items (such as deferred taxes) that reflect sources of financing available to the company.<sup>578</sup>

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.

In this case, DTE seeks an overall return of 6.04% to set rates.<sup>579</sup> Staff recommends an overall rate of return of 5.78%, and the Attorney General recommends

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<sup>577</sup> 4 Tr 1752.

<sup>578</sup> Case No. U-16794, Order, June 7, 2012, p. 40.

<sup>579</sup> DTE initial brief, p. 80.

an overall rate of return of 5.82%.<sup>580</sup> The differences are attributable to a disagreement concerning Consumers' common equity balance, long-term debt, and proposed ROE.

### **Test Year Capital Structure**

The Commission has long determined that a balanced capital structure reflects equal amounts of debt and equity as a percentage of Consumers' permanent capital structure.

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.<sup>581</sup>

### **DTE**

Mr. Lepczyk is recommending a projected test year permanent capital structure of 48.5% long-term debt and 51.5% equity.<sup>582</sup>

Mr. Lepczyk is forecasting 4.44% for the cost of DTE Gas's long-term debt, and 5.95% for the cost of DTE Gas's short-term debt, while noting that DTE does not have preferred stock and therefore it has no cost rate.<sup>583</sup>

Mr. Lepczyk states that total regulatory capital structure may include long-term debt, short-term debt, preferred equity, common equity, deferred taxes, deferred job development investment tax credits, and deferred investment tax credits, while rating agencies' and credit analysts' calculation of a company's capital structure includes short-

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<sup>580</sup> Staff initial brief, p. 18; Ex. AG-22.

<sup>581</sup> Case No. U-17990, Order, February 28, 2017, p. 63-64. Citation omitted.

<sup>582</sup> 4 Tr 2188, 8; Ex. A-14, Sch. D1.

<sup>583</sup> Id.; Ex. A-14, Sch. D2, D3.

term debt, long-term debt, preferred equity, and common equity, as well as other adjustments to include items such as leases, off-balance sheet obligations, unfunded pension liabilities, and asset retirement obligations.<sup>584</sup>

Mr. Lepczyk states that a firm such as DTE Gas faces two types of risk: business risk and financial risk.<sup>585</sup> He adds that financial risk is the risk that common equity shareholders face to the extent that a firm issues debt to finance its assets, with the greater the amount of debt held by a firm, the greater the risk to common shareholders.<sup>586</sup> He asserts that it is essential that a firm recognizes the dynamics of these risks and adjusts its underlying debt and equity components to produce a sound capital structure.<sup>587</sup>

Mr. Lepczyk states that having a weak or highly leveraged capital structure may lead to higher required returns on equity and a higher cost of debt, and it also can impact the company's ability to obtain capital.<sup>588</sup>

While he admits that the Commission has consistently shown its preference for a 50% equity, 50% debt, or "balanced" capital structure, such that the Commission has stated that utilities including DTE Gas should move toward a more balanced capital structure, Mr. Lepczyk asserts that there are compelling business and financial reasons for DTE Gas's capital structure to consist of 52% [sic] equity.<sup>589</sup>

Mr. Lepczyk states that DTE believes that a capital structure composed of 51.5% equity is a balanced capital structure when capital structure is looked at on an adjusted

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<sup>584</sup> 4 Tr 2189.

<sup>585</sup> 4 Tr 2190.

<sup>586</sup> Id.

<sup>587</sup> Id.

<sup>588</sup> Id.

<sup>589</sup> 4 Tr 2191. This statement includes "52%" instead of "51.5%", which is the equity percentage consistently referenced in Mr. Lepczyk's testimony. Thus, this PFD considers this "52%" to be a typo.

basis, noting that the calculation of capital structure on a regulatory basis does not include several factors the rating agencies include, most importantly short-term debt, and that DTE Gas has a proportionally larger short-term debt balance than other utilities.<sup>590</sup> He states that at 51.5% equity DTE Gas is, when short term debt is considered, in fact, at a balanced capital structure, noting that the equity capitalization ratio falls to approximately 49.8% when short-term debt is included in the leverage calculation.<sup>591</sup> He notes that rating agencies and investors calculate DTE Gas's credit ratios with short-term debt in the calculation.<sup>592</sup>

While he supports DTE Electric's 50% equity ratio and consider it to be a balanced and fair capital structure, Mr. Lepczyk asserts that the capital structures of DTE Electric and DTE Gas are different.<sup>593</sup> He states that there are meaningful differences between DTE Electric and DTE Gas's respective balance sheets (DTE Electric assets are over 4x the size of DTE Gas) their average annual return of capital (i.e., depreciation (DTE Electric 4.2% vs DTE Gas 2.8%)) and their respective contributions to operating cash flows (DTE Electric is 3.5x DTE Gas), such that DTE Electric's and DTE Gas's respective capital structures should not be treated the same.<sup>594</sup>

Mr. Lepczyk states that DTE Gas, like DTE Electric, needs strong access to capital, especially given DTE Gas's significant capital expenditure plans.<sup>595</sup>

Mr. Lepczyk asserts that he determined other key factors that support the proposed DTE Gas equity ratio of 51.5% include a) peer equity ratios are higher, b) DTE

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<sup>590</sup> 4 Tr 2195-2196, Table 1.

<sup>591</sup> Id., 4 Tr 2192.

<sup>592</sup> 4 Tr 2192.

<sup>593</sup> Id.

<sup>594</sup> Id.

<sup>595</sup> Id.

Gas has higher short-term debt than other Michigan utilities, c) DTE Gas is significantly smaller in size than its peer Michigan utilities, and d) DTE's ability to withstand variability in cash flows is more challenged.<sup>596</sup>

Mr. Lepczyk states that a 51.5% equity level is below the average 2022 equity level of 53.8% for peer gas Local Distribution Companies ("LDC").<sup>597</sup> He adds that he used the same proxy group used by Dr. Villadsen in her ROE analysis, asserting that the peer group used to compare the capital structure of DTE Gas should be that of other operating gas utility companies and not holding companies.<sup>598</sup>

Mr. Lepczyk states that he foresees "rating agency concerns" if DTE Gas moved to a 50/50 regulatory basis capital structure.<sup>599</sup> He asserts that the rating agencies' debt adjustments support the need for DTE Gas to maintain a relatively higher equity ratio before adjustment to be on par with comparable utilities after adjustment, arguing that DTE Gas's short-term debt levels add a much greater burden on its credit metrics than that of its peers.<sup>600</sup>

Mr. Lepczyk states that DTE Gas is committed to maintaining a 51.5% equity ratio and has demonstrated its commitment to its targeted equity ratio by receiving equity infusions from DTE Energy when needed to maintain its targeted equity ratio.<sup>601</sup> He adds that DTE Energy has made reasonable efforts to strengthen DTE Gas's credit quality by infusing \$216 million of common equity in 2023, and that this infusion and planned equity infusions in 2023 through 2025 are consistent with DTE Gas's previous goal of

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<sup>596</sup> 4 Tr 2193-2194.

<sup>597</sup> 4 Tr 2194; Ex. A-17, Sch. G3.

<sup>598</sup> Id.

<sup>599</sup> 4 Tr 2196.

<sup>600</sup> 4 Tr 2197, 2198.

<sup>601</sup> Id.

maintaining a capital structure with a common equity ratio as a percentage of permanent capital of approximately 51.5%.<sup>602</sup>

Mr. Lepczyk states that DTE Gas's and DTE Energy's current and historical credit ratings, along with associated rating agency outlooks, for the previous five years as published by S&P Global Ratings, Moody's and Fitch Ratings are shown in Ex. A-17, Sch. G1.<sup>603</sup>

### **Staff**

Staff agrees with all of DTE's recommended capital structure balances except for long-term debt and common equity.<sup>604</sup>

Mr. Ufolla states that the difference between Staff and DTE's long-term debt and common equity balances is due to a difference in what DTE and Staff recommend as a reasonable equity ratio, with Staff shifting some of the proposed capital structure from the common equity layer to long-term debt.<sup>605</sup>

Mr. Ufolla states that Staff recommending as a common equity ratio of 51.00%.<sup>606</sup> He asserts that authorizing an appropriate equity ratio is crucial to ratepayers as equity is more costly than debt, such that the higher the equity ratio, the higher customer rates are.<sup>607</sup>

Mr. Ufolla asserts that DTE's recommended 51.50% equity ratio is too high, with an equity ratio of 50% - 51% being more appropriate.<sup>608</sup> Noting that DTE's currently

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<sup>602</sup> Id.

<sup>603</sup> 4 Tr 2204.

<sup>604</sup> 4 Tr 1613.

<sup>605</sup> Id.

<sup>606</sup> Id.

<sup>607</sup> Id.

<sup>608</sup> 4 Tr 1614.

approved equity ratio is 51%, he states that Staff uses 51.00% for the development of exhibits in the instant case, and that an authorization of a 51.00% equity ratio in the instant case would allow for a smoother transition to a balanced equity ratio of 50% in a future case.<sup>609</sup>

Mr. Ufolla notes that the Commission has signaled a preference for DTE Gas to have a more balanced equity ratio.<sup>610</sup> He adds that DTE acknowledges this, indicating in a prior case that the Commission has consistently shown a preference for a 50% equity, 50% debt, or ‘balanced’ capital structure,” and noting that in a recent rate case, the settlement agreement stated that DTE Gas would move toward a more balanced capital structure.<sup>611</sup>

Mr. Ufolla asserts that changing the equity ratio in DTE’s initial filing, from 51.50% to 51.00%, would reduce the revenue requirement by approximately \$2.7 million.<sup>612</sup> He adds that the effect on DTE’s credit rating of this change would be no different than any other reduction to the revenue requirement.<sup>613</sup> He asserts that a company can operate at any capital structure it chooses, regardless of the capital structure authorized by the Commission, and that the financial ratios which credit rating agencies use in their analysis, primarily FFO/Debt (or CFO/Debt) and EBITA/Debt, are based on the operational capital structure of the Company not the ratemaking capital structure.<sup>614</sup> Noting that Moody’s has stated that the CFO/Debt metric would be a concern if the metric fell to 16%, he argues that with Staff’s adjustments of 51% equity and 9.80% ROE, Staff

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<sup>609</sup> Id.

<sup>610</sup> 4 Tr 1614-1615, quoting Case No. U-18999, Order, September 13, 2018, p. 43-44.

<sup>611</sup> 4 Tr 1615, referencing Case No. U-26042 (sic) [U-20642]. Citation omitted.

<sup>612</sup> Id.

<sup>613</sup> Id.

<sup>614</sup> 4 Tr 1615-1616. Citation omitted.

calculates a basic CFO/Debt ratio of 18.5%.<sup>615</sup> He adds that although this is not the precise formula Moody's employs to calculate CFO/Debt, DTE Gas is far above the 16% threshold the rating agency has established.<sup>616</sup>

Mr. Ufolla notes that Mr. Lepczyk mentions the CFO-Dividends/Debt ratio and adds that this is not the metric specifically listed in the "Factors that could lead to a downgrade" section of Moody's July 3, 2023 Credit Opinion.<sup>617</sup>

Mr. Ufolla states that in 2019 Moody's downgraded DTE Gas from Aa3 to A1, which he asserts was not unforeseen as DTE was placed on a negative outlook over a year before this downgrade occurred.<sup>618</sup> He adds that the downgrade still leaves DTE a very comfortable 6 notches above the lowest investment grade rating.<sup>619</sup> He asserts that ultimately DTE Gas still has a healthy credit rating, and this past downgrade does not justify deviating from the previous Commission order in U-18999 or the Settlement agreement from U-20642.<sup>620</sup>

### **Attorney General**

Mr. Coppola recommends a capital structure made up of 50% long-term debt and 50% common equity for the test period ending September 2025.<sup>621</sup> As such, he states that he reduced the level of common equity to \$2.749 billion, which is an \$82 million reduction from DTE's case and an inclusion of this \$82 million amount as additional long-term debt.<sup>622</sup>

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<sup>615</sup> 4 Tr 1616. Footnote omitted.

<sup>616</sup> Id., n. 4, citing Moody's Investor Service Credit Opinion - July 25, 2023.

<sup>617</sup> 4 Tr 1616-1617.

<sup>618</sup> 4 Tr 1617, noting that Moody's placed DTE Gas on a negative outlook in May 2018 and downgraded DTE in July 2019. Id., n. 9.

<sup>619</sup> Id.

<sup>620</sup> Id.

<sup>621</sup> 4 Tr 1480; Ex. AG-22.

<sup>622</sup> Id.

Mr. Coppola states that he increased long-term debt and reduced common equity to achieve a 50%/50% capital structure for a few reasons. He asserts that the common equity ratio of the peer group is approximately 46%, which lower average common equity level supports these companies' utility operations as well as non-utility operations, which tend to be somewhat riskier.<sup>623</sup> He adds that the riskier non-utility operations require a higher common equity cushion to maintain similar credit ratings, such that if he adjusted for the higher equity capital required by the non-utility businesses, the equity capital for the utility portion of the peer group's capital structure would be lower than 46%.<sup>624</sup>

In addition, Mr. Coppola notes that in Case U-18999, the Commission directed DTE to develop a plan to move to a 50%/50% balanced capital structure.<sup>625</sup> He asserts that DTE Gas is a captive subsidiary of DTE Energy and that DTE Energy can make the common equity ratio of DTE Gas whatever it wants.<sup>626</sup> He argues that as a result, DTE Energy management has artificially set the common equity ratio of DTE Gas at nearly 52.6%, when the parent company only has a common equity ratio of approximately 36.5%.<sup>627</sup>

Mr. Coppola states that the average common equity ratio of the peer company group for 2023 was 45.7%, and that the cost of equity capital for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure.<sup>628</sup> He asserts that it is critical to synchronize the capital structure of DTE to the peer group average as closely as possible in order to have consistency with the cost of equity capital

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<sup>623</sup> 4 Tr 1481; Ex. AG-25.

<sup>624</sup> Id.

<sup>625</sup> Id.

<sup>626</sup> Id.

<sup>627</sup> 4 Tr 1482.

<sup>628</sup> Id.

derived from those peer group companies.<sup>629</sup> He argues that DTE's proposed common equity capital ratio of 51.5% creates a disconnect that is not acceptable, and that is more costly to customers.<sup>630</sup>

Mr. Coppola disagrees with Mr. Lepczyk's calculation of a 53.8% equity ratio from a group of purported peer utilities.<sup>631</sup> He asserts that the data points were inconsistent, and that Mr. Lepczyk should have used an average equity ratio over a 12-month period or over four quarters to develop an appropriate comparison to DTE's proposed equity ratio.<sup>632</sup> He argues that the equity ratio of 53.8% does not represent the average equity ratio approved by the state commissions regulating those companies, with DTE attempting to portray the equity ratios of the companies, as the equity ratios were calculated by DTE using equity capital balances reported by the companies in their public financial reports as of either September 2022 or December 2022 and as published by S&P Global Market Intelligence, with no further adjustments by DTE.<sup>633</sup> He adds that the utility companies included in this peer group are captive subsidiaries and that management can set the capital structure of those companies to any desired level for financial reporting and are not necessarily reflective of the permanent capital structure approved in rates.<sup>634</sup> He asserts that the peer group of companies included in Ex.A-17, Sch. G3, includes only a select group of utilities and is not the same list of companies used by DTE's cost of equity witness in determining the cost of equity.<sup>635</sup>

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<sup>629</sup> Id.

<sup>630</sup> Id.

<sup>631</sup> 4 Tr 1483.

<sup>632</sup> 4 Tr 1483-1484.

<sup>633</sup> 4 Tr 1484.

<sup>634</sup> Id.

<sup>635</sup> Id.

Mr. Coppola disagrees with Mr. Lepczyk that DTE's use of more short-term debt requires a higher common equity ratio, and asserts that Mr. Lepczyk's comparison of DTE Gas's short-term debt being higher to the short-term debt of DTE Electric and of Consumers Energy on December 31, 2022 is problematic as short-term has a seasonal pattern and balances vary throughout the year.<sup>636</sup> He adds that the issuance of long-term debt and the timing of those issuances affect the amount of short-term debt at any point in time, as cash raised from long-term financing pays down short-term debt used to temporarily finance capital programs.<sup>637</sup>

Mr. Coppola disagrees with Mr. Lepczyk's assertion that the smaller size of DTE compared to other Michigan utilities justifies a higher equity ratio.<sup>638</sup> He states that the comparison of DTE Gas to electric utilities or combination gas and electric companies is inappropriate and not relevant in setting the equity ratio for DTE's capital structure.<sup>639</sup> He adds that, as DTE Gas is far larger than the other two gas utilities in Michigan -- Michigan Gas Utilities Corporation and SEMCO Energy Gas Company -- and that DTE Gas is the fifth largest gas utility of the 14 companies shown in Ex. A-17, Sch. G3.<sup>640</sup>

Mr. Coppola states that Mr. Lepczyk presents no evidence that a 51.5% equity ratio is necessary to access the capital markets or that a balanced capital structure with 50% equity and 50% long-term debt would inhibit access to the capital markets.<sup>641</sup> He states that Mr. Lepczyk's claim that a move to a 50/50 capital structure may be seen as

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<sup>636</sup> 4 Tr 1485.

<sup>637</sup> Id.

<sup>638</sup> 4 Tr 1486.

<sup>639</sup> Id.

<sup>640</sup> Id.; Ex. A-17, Sch. G3.

<sup>641</sup> 4 Tr 1487.

an adverse change in the regulatory environment is without evidentiary support.<sup>642</sup> He notes that the Commission has signaled its desire for a balanced 50/50 permanent capital structure for Michigan utilities for several years and in a March 2024 order in Case No. U-21389, the Commission approved a common equity ratio of 50.02% for Consumers Energy.<sup>643</sup> He states that in the latest Moody's report on DTE dated July 25, 2023, the rating agency stated that "a rating upgrade could be possible if DTE Gas's financial metrics remain at current levels, such as the cash flow to debt ratio continuing to be in excess of 19%."<sup>644</sup>

Mr. Coppola notes the Commission's directive to DTE in Case No. U-18999 that DTE shall articulate its strategy to return to a balanced capital structure and the steps that it will take to reach the goal.<sup>645</sup> He adds that the settlement agreement reached in the next rate case (Case No. U-20642) stated that DTE agreed to file a plan in its next rate case (Case No. U-20940) that would move DTE toward a more balanced structure.<sup>646</sup> He states that in Case No. U-20940, while DTE proposed only a slight decline in common equity ratio from 52% to 51.9%, the Commission approved a 51% common equity ratio, stating, in part, that "as stated by Staff, DTE Gas 'can operate at any capital structure it chooses', and as noted by Mr. Coppola, DTE can infuse as much equity capital into DTE Gas as it sees fit."<sup>647</sup> He adds that DTE is making arguments in this case for a higher common equity ratio of 51.5%, rather than the 51% approved in the last rate case.<sup>648</sup>

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<sup>642</sup> Id.

<sup>643</sup> Id.

<sup>644</sup> Id.

<sup>645</sup> 4 Tr 1488, citing Case No. U-18999, Order, September 13, 2018, p. 127.

<sup>646</sup> 4 Tr 1489.

<sup>647</sup> Id., citing Case No. U-20940, Order, December 29, 2021, p. 77.

<sup>648</sup> 4 Tr 1489-1490.

Mr. Coppola states that he calculated the impact on the Moody's cash flow to debt coverage ratio based on a 50% equity ratio and an authorized ROE of 9.85%, with the overall pro-forma results showing a cash flow to debt ratio of 19.3%, which is well above the 16% sustained ratio threshold that could trigger a credit rating downgrade as stated by Moody's in its July 25, 2023 report.<sup>649</sup> He adds that he did not present any ratio results for S&P since the ratio calculations are similar and the S&P downgrade threshold is lower at 11%.<sup>650</sup>

Mr. Coppola states that if the Commission were to adopt a 51.5% common equity ratio instead of a 50% ratio in this case, the annual revenue requirement would be higher by approximately \$7.8 million.<sup>651</sup> He adds that this reflects DTE's shift of approximately \$81 million from long term debt to common equity capital and the difference between DTE's pretax cost of common equity of 14% versus the pretax cost of long-term debt of approximately 4%.<sup>652</sup>

### **ABATE**

Mr. Walters states that in general, the utility industry's common equity ratios have not deviated too much from the range of 50.0% to 52.0%.<sup>653</sup>

Mr. Walters states DTE's proposed equity ratio of 51.50% significantly exceeds the equity ratio for the proxy group used to estimate the cost of equity for DTE, noting that the proxy group has an average common equity ratio of 44.4% (including short-term debt)

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<sup>649</sup> 4 Tr 1490-1491; Ex. AG-30.

<sup>650</sup> 4 Tr 1491.

<sup>651</sup> Id.

<sup>652</sup> Id.

<sup>653</sup> W Tr 5, Table CCW-2. Mr. Walters states that he excluded the reported authorized common equity ratios for Arkansas, Florida, Indiana, and Michigan as these jurisdictions include sources of capital outside of investor-supplied capital such as accumulated deferred income taxes, such that the reported common equity ratios in these states would result in a downward bias in the reported permanent common equity ratios authorized for ratemaking purposes within my trend analysis. Id.

and 50.0% (excluding short-term debt).<sup>654</sup> He adds that DTE's request flies in the face of this Commission's previous Order in U-20940 where it authorized an equity ratio of 51.0%.<sup>655</sup> He notes that in that same Order, the Commission stated that authorizing an equity ratio of 51%, instead of DTE's requested 52%, represented "a reasonable transition to a more balanced capital structure".<sup>656</sup> He asserts that DTE's requested equity ratio of 51.5% moves in the opposite direction of the Commission's explicit directive to move toward a capital structure consisting of 50% equity.<sup>657</sup> He also states that the Commission's Order in U-20940 makes reference to explicit directives it provided in the August 20, 2020 Order in U-20642 as well as the September 13, 2018 Order in U-18999, directing DTE to move towards a more balanced capital structure.<sup>658</sup> He asserts that despite the Commission recognizing the need for DTE to move toward a balanced capital structure, and having provided DTE several directives to do so, DTE ignores these explicit directives and requests an equity ratio exceeding what the Commission has directed it to do.<sup>659</sup> He states that his proxy group in this case has an average common equity ratio of 44.4% (including short-term debt) and 50.0% (excluding short-term debt) as calculated by S&P Global Market Intelligence and Value Line, respectively.<sup>660</sup>

Mr. Walters states that DTE has not reasonably demonstrated a need to be awarded a common equity ratio well in excess of 50.0%.<sup>661</sup> He asserts that a common equity ratio of 50.0% is consistent with this Commission's stated preference for a

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<sup>654</sup> 4 Tr 1359; Ex. AB-5.

<sup>655</sup> Id.

<sup>656</sup> Id.

<sup>657</sup> 4 Tr 1359-1360, citing Case No. U-20940, Order, p. 77.

<sup>658</sup> 4 Tr 1360, citing Case No. U-20940, Order, p. 76.

<sup>659</sup> Id.

<sup>660</sup> 4 Tr 1360-1361.

<sup>661</sup> 4 Tr 1361.

balanced capital structure consisting of permanent equity ratios of 50% in previous rate cases, and as such, he recommends the Commission authorize DTE an equity ratio of 50.0%.<sup>662</sup> He adds that should the Commission authorize DTE its requested equity ratio of 51.50%, an ROE in the lower half of his recommended range (i.e. 9.1% to 9.45%) would be warranted.<sup>663</sup>

### **Rebuttal**

On rebuttal, regarding Mr. Coppola's assertion that the equity ratio of 53.8% does not represent the average equity ratio approved by the state commission regulating those commissions, Mr. Lepczyk states that Mr. Coppola's calculation is flawed since it does not utilize the equity ratios approved by the state commissions regulating those companies.<sup>664</sup> He adds that his exhibit shows that the authorized common equity ratio approved by the state commissions for the peer group gas operating companies is 53.8% and is consistent with DTE's request for an authorized equity ratio of 51.5%.<sup>665</sup> Mr. Lepczyk similarly states that Mr. Walters assertions of the average common equity ratio is contradicted by his same exhibit.<sup>666</sup>

In rebuttal, Mr. Walters takes issue with Staff's recommendation that DTE be allowed to maintain its existing permanent common equity ratio of 51.0% despite the explicit preference of this Commission that DTE's common equity ratio move toward a balanced level of 50.0%.<sup>667</sup> Noting that Mr. Ufolla states that DTE's currently approved equity ratio is 51% and that an authorization of a 51% equity ratio in the instant case

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<sup>662</sup> Id.

<sup>663</sup> Id.

<sup>664</sup> 4 Tr 2208-2209.

<sup>665</sup> 4 Tr 2209; Ex. A-35, Sch. Y1, Y2.

<sup>666</sup> Id.

<sup>667</sup> 4 Tr 1412.

“would allow for a smoother transition to a balanced equity ratio of 50% in a future case,” Mr. Walters counters that there is no transition taking place now at his recommendation of 51.0%.<sup>668</sup> Noting that the Commission has provided explicit directives for DTE to move toward a capital structure consisting of 50% equity in several orders, Mr. Walters asserts that Mr. Ufolla ignores the Commission’s stated preference in recommending the status quo be maintained instead of transitioning to an equity ratio of 50.0%.<sup>669</sup>

### **Recommended Capital Structure**

After reviewing the record and the arguments of the parties, this PFD finds that DTE has not established that its request for a capital structure with an equity ratio of 51.5% is reasonable and consistent with prior Commission orders, nor that a continuing deviation from a capital structure evenly balanced between debt and equity is appropriate.

As indicated, *supra.*, the Commission has long determined that a balanced capital structure reflects equal amounts of debt and equity as a percentage of a utility’s permanent capital structure. See, Case No. U-16794, Order, June 12, 2012, p. 44. (“The Commission has recognized that a financially healthy public utility should have a relatively balanced capital structure.”) See, also, its Order in Case No. U-17990 wherein the Commission stated:

The Commission desires to arrive at an optimized capital structure that is both supportive of planned infrastructure investments, yet is not unnecessarily burdensome on ratepayers. The Commission also anticipates that a cycle of heavier-than-usual investment will present an ideal opportunity to rebalance Consumers’ capital structure to reach its 50/50 goal. In the next rate case, the Commission expects that Consumers will have arrived at, or will present a strategy to return to, a balanced structure within the five-year infrastructure plan time period. If Consumers is unable to do so, a more complete analysis should be included to explain why such a result is reasonable and prudent. . . .<sup>670</sup>

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<sup>668</sup> 4 Tr 1413. Citation omitted.

<sup>669</sup> Id., referencing orders in Case Nos. U-20940, U-20642, and U-18999.

<sup>670</sup> Case No. U-17990, Order, February 28, 2017, p. 64. Citation omitted.

Similarly, in a following gas rate case (Case No. U-18124), the Commission reiterated the importance of maintaining a capital structure evenly balanced between debt and equity.

Consumers' treatment as a stand-alone company for ratemaking purposes requires it to maintain a capital structure that is evenly balanced between debt and equity. And, although Consumers asserts that a balanced capital structure is its goal, its proposed equity ratio continues to increasingly favor equity capital over debt capital at the expense of its ratepayers. . . .

The Commission cannot overemphasize the company's responsibility to rebalance its equity and debt capital. The Commission agrees with the Attorney General that, considering the size of Consumers' capital portfolios, a few percentage point increase to the equity balance translates into an increase of millions of dollars, and may unnecessarily increase costs to customers. . . .<sup>671</sup>

Thereafter, in subsequent cases, the Commission has consistently stated that DTE needs to move to an evenly balanced capital structure. See, Case No. U-18999, Order, September 13, 2018, p. 43-44. ("The Commission agrees with the ALJ and adopts the PFD's recommendation that the Commission should encourage DTE Gas to move to a more balanced 50/50 capital structure. As the Commission has stated, "[a] common equity ratio that is unnecessarily equity-heavy burdens ratepayers because equity capital is more expensive than debt capital and carries with it the additional expense of a tax burden that is not present with debt capital." Citation omitted); Case No. U-20940, Order, date, p. 76 ("In DTE Gas's last rate case, Case No. U-20642, the Commission approved a settlement agreement [which] settlement agreement stated that 'DTE Gas will file a plan in its next rate case that moves toward a more balanced capital structure.'" Citation omitted.)

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<sup>671</sup> Case No. U-18124, Order, July 31, 2017, p. 45-46.  
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The Attorney General and ABATE recommend a capital structure evenly balanced between debt and equity in accordance with the Commission's prior orders.<sup>672</sup> Mr. Coppola asserts that the Commission has signaled its desire for a balanced 50/50 permanent capital structure for Michigan utilities for several years.<sup>673</sup> This PFD agrees. Similarly, Mr. Walters asserts that DTE's request for an equity ratio of 51.50% "flies in the face of this Commission's previous Order in U-20940 where it authorized an equity ratio of 51.0%," and that DTE's requested equity ratio of 51.5% "moves in the opposite direction of the Commission's explicit directive to move toward a capital structure."<sup>674</sup> Again, this PFD agrees.

Mr. Lepczyk asserts that that a capital structure composed of 51.5% equity is a balanced capital structure when capital structure is looked at on an adjusted basis, as the calculation of capital structure on a regulatory basis does not include several factors the rating agencies including, most importantly short-term debt.<sup>675</sup> He notes that DTE's equity capitalization ratio as adjusted falls to approximately 49.8% when short-term debt is included in the leverage calculation.<sup>676</sup> This argument is unsupported. Clearly the 50/50 balance that the Commission has directed concerns DTE's regulatory capital structure. See, e.g., Case No. U-18124, Order, July 31, 2017, p. 45 ("Consumers' treatment as a stand-alone company for ratemaking purposes requires it to maintain a capital structure that is evenly balanced between debt and equity."). Moreover, this PFD notes that, as

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<sup>672</sup> 4 Tr 4 Tr 1480; 4 Tr 1361.

<sup>673</sup> 4 Tr 1487.

<sup>674</sup> 4 Tr 1359.

<sup>675</sup> 4 Tr 2195.

<sup>676</sup> 4 Tr 2191-2192.

such, the Commission has rejected this same argument in previous rate cases. See, e.g., Case No. U-20963 Order

The Commission agrees with the ALJ that Consumers' adjusted equity ratio is not sufficient to demonstrate that the company's proposed 52% equity is reasonable and prudent in this case. The ALJ properly found that the Commission has previously rejected the company's assertion of a more balanced capital structure when considering the equity ratio from a credit rating agency perspective. . . . The Commission finds that the company's adjusted capital structure does not reflect the appropriate balance and represents a departure from the 'established ratemaking method that develops a weighted cost of capital based on the sources of financing rate base.'<sup>677</sup>

Mr. Lepczyk asserts that, while he considers DTE Electric's 50% equity ratio to be a balanced and fair capital structure, there are meaningful differences between DTE Electric and DTE Gas's respective balance sheets -- DTE Electric assets are over 4x the size of DTE Gas, their average annual return of capital differs, and DTE Electric's contributions to operating cash flows is 3.5x DTE Gas -- such that DTE Electric's and DTE Gas's respective capital structures should not be treated the same.<sup>678</sup> Mr. Coppola counters that the comparison of the size of DTE gas to electric utilities is not relevant in setting the equity ratio for DTE's capital structure.<sup>679</sup> This PFD agrees, as the balance the Commission desires in determining an appropriate capital structure is that "between the risks and costs of investor and debt funding" for the utility at issue.<sup>680</sup>

Mr. Lepczyk asserts that DTE Gas needs strong access to capital, especially given DTE Gas's significant capital expenditure plans.<sup>681</sup> Mr. Coppola counters that Mr. Lepczyk presents no evidence that a 51.5% equity ratio is necessary to access the capital markets

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<sup>677</sup> Case No. U-20963, Order, December 22, 2021, p. 203-204. Citations omitted.

<sup>678</sup> 4 Tr 2192.

<sup>679</sup> 4 Tr 1486.

<sup>680</sup> See, Case No. U-17990, Order, February 28, 2017, p. 63-64.

<sup>681</sup> 4 Tr 2192.

or that a balanced capital structure with 50% equity and 50% long-term debt would inhibit access to the capital markets.<sup>682</sup> Mr. Coppola adds that other utilities are able to easily access the capital markets with lower equity ratios and lower approved return on equity rates.<sup>683</sup> This PFD agrees. Moreover, this PFD notes that the Commission previously stated that a period of heavy capital expenditures is an “ideal opportunity” to rebalance a capital structure to reach a 50/50 debt/equity balance. See, Case No. U-17990, Order, February 28, 2017, p. 64 (“The Commission also anticipates that a cycle of heavier-than-usual investment will present an ideal opportunity to rebalance Consumers’ capital structure to reach its 50/50 goal.”)

Mr. Lepczyk states that he foresees “rating agency concerns” should a 50/50 capital structure be an outcome of this proceeding.<sup>684</sup> Noting that Moody’s July 2023 DTE Gas Credit Opinion states that a rating downgrade could be triggered “if there is an adverse change in the Michigan regulatory environment, increasing regulatory lag, or if the company experiences insufficient cost recovery or returns,” Mr. Lepczyk asserts that a move to a 50/50 capital structure may be seen as an adverse change in the regulatory environment.<sup>685</sup> This argument is unsupported.

As Mr. Coppola notes, Mr. Lepczyk offers no analysis or other evidence to support his claim that a move to a 50/50 capital structure may be seen as an adverse change in the regulatory environment.<sup>686</sup> Mr. Coppola adds that the Commission has signaled its desire for a balanced 50/50 permanent capital structure for Michigan utilities for several

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<sup>682</sup> 4 Tr 1487.

<sup>683</sup> Id.

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<sup>685</sup> Id.

<sup>686</sup> 4 Tr 1487.

years and suggests that the credit reports for DTE and other utilities would make reference to a 50/50 capital structure being problematic if the credit agencies considered it to be so.<sup>687</sup> Similarly, in discussing Moody's 2019 downgrade of DTE Gas from Aa3 to A1, Mr. Ufolla notes that the downgrade still leaves DTE a very comfortable six notches above the lowest investment grade rating.<sup>688</sup> Thus, he asserts that DTE Gas still has a healthy credit rating, and this past downgrade does not justify deviating from the previous Commission order in U-18999 or the Settlement agreement from U-20642 which provide for DTE to move toward a more balanced 50/50 capital structure.<sup>689</sup> Indeed, this PFD notes that DTE's exhibit shows that DTE Gas's current and historical credit ratings published by S&P Global Ratings, Moody's and Fitch Ratings for the previous five years show DTE with a solid and consistent credit rating.<sup>690</sup>

DTE argues that the average equity ratios of peer LDC gas companies for 2022 – 53.8% -- are significantly greater than the equity ratio it seeks in this case, which it asserts supports its proposed 51.50% equity ratio.<sup>691</sup> However, DTE essentially abandons its own argument in this regard, as in its testimony, DTE nonetheless proposes a common equity balance well below the peer companies' equity ratio averages that it references.<sup>692</sup>

More importantly, the equity ratios of peer group companies are not informative of what is an appropriate equity ratio for DTE. As discussed, *supra*, the Commission has determined that the appropriate capital structure is based on cost and risk considerations

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<sup>687</sup> Id.

<sup>688</sup> 4 Tr 1617. Citation omitted.

<sup>689</sup> Id. Citations omitted.

<sup>690</sup> 4 Tr 2204; Ex. A-17, Sch. G1.

<sup>691</sup> 4 Tr 2194; Ex. A-17, Sch. G3.

<sup>692</sup> Id.

from the perspective of the utility and its ratepayers, not from the perspective of a comparison with the equity ratios of peer companies.

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. . . . Thus, the Commission seeks an appropriate balance between the risks and costs of investor and debt financing.<sup>693</sup>

Indeed, it appears that utilities have begun to use a comparison with peer company equity ratios merely based upon the fact that the Commission, consistent with the Supreme Court standards, has considered national averages of authorized ROEs when determining an appropriate authorized ROE for a utility.<sup>694</sup>

Having found that Consumers has not established the reasonableness of its proposed 51.50% equity ratio, this PFD considers the equity ratio recommendations of Staff, the Attorney General and ABATE.

Staff's recommendation is curious. On the one hand, Mr. Ufolla states a) that authorizing an appropriate equity ratio is crucial to ratepayers as equity is more costly than debt, such that the higher the equity ratio, the higher the customer rates, b) that the Commission has consistently shown a preference for a 50% equity and 50% debt "balanced" capital structure, and c) that in the recent DTE Gas rate case (Case No. U-26042) the settlement agreement stated that DTE Gas would move toward a more balanced capital structure.<sup>695</sup> On the other hand, while stating that an equity ratio of 50%-

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<sup>693</sup> Case No. U-17999, Order, February 28, 2017, p. 63-64. Citation omitted.

<sup>694</sup> See, Case No. U-20697, Dkt. No. 0433, 4 Tr 662, testimony of Consumers' witness Marc R. Bleckman

"In Case No. U-20322, the Company's most recent gas rate case, Staff considered national averages of authorized ROEs in developing its ROE recommendation. In its Order in that case, the Commission cited Staff's average ROE analysis as one of the factors considered in determining the Company's approved ROE. . . . Staff and the Commission considered peer averages an important piece of evidence in the ratemaking process. To be consistent with that philosophy, it is appropriate to consider peer company equity ratio averages and trends in determining the equity ratio for the Company in this case."

<sup>695</sup> 4 Tr 1613, 1615.

51% is more appropriate than DTE's proposed 51.50%, Staff uses a 51% equity ratio for its exhibits, asserting that an authorization of a 51.00% equity ratio in the instant case would allow for a smoother transition to a balanced equity ratio of 50% in a future case."<sup>696</sup> Mr. Walters counters that there is no transition taking place now at Staff's recommendation of 51.0% equity ratio and that Staff ignores the Commission's stated preference in recommending the status quo be maintained instead of transitioning to an equity ratio of 50.0%.<sup>697</sup> This PFD agrees.

As indicated, the Attorney General and ABATE recommend a 50% equity ratio which this PFD finds is reasonable, is supported by the evidence, and is consistent with the Commission's prior orders that DTE return to a balanced 50/50 capital structure. Moreover, as the Commission directed DTE to move to a 50/50 balanced capital structure in 2018<sup>698</sup>, and despite having six years to transition to a balanced capital structure, DTE continues to slow-walk – indeed, reverse course on -- any such transition. As such, DTE should be required to adopt a 50/50 balanced capital structure at this time.

Accordingly, this PFD recommends the Commission adopt the Attorney General's proposed common equity balance of \$2.749 billion, which represents approximately 50.0% of the permanent capital structure and 39.59% of the ratemaking capital structure, as set forth in Appendix D to this PFD.

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<sup>696</sup> 4 Tr 1614.

<sup>697</sup> 4 Tr 1413. Citations omitted.

<sup>698</sup> See, Case No. U-18999, Order, September 13, 2018, p. 43-44. ("The Commission agrees . . . that [it] should encourage DTE Gas to move to a more balanced 50/50 capital structure.")

### **Long-Term Debt Balance**

DTE projects a long-term debt balance of \$2.667 billion.<sup>699</sup>

The Attorney General proposes a long-term debt balance of \$2.749 billion, a decrease of \$82 million from DTE's projected long-term debt balance.<sup>700</sup> Mr. Coppola states that the permanent capital balances reflect two changes: he reduced the level of common equity to \$2.749 billion, which is an \$82 million reduction from DTE's case, and he included this \$82 million amount as additional long-term debt.<sup>701</sup> Mr. Coppola adds that the result is the allocation of the total permanent capital of \$5.5 billion to 50% long-term debt and 50% common equity.<sup>702</sup>

Staff proposes a long-term debt balance of \$2.694 billion.<sup>703</sup> Mr. Ufolla states that the difference between Staff and the DTE's Long-Term Debt and Common Equity balances is due to a difference in what DTE and Staff recommend as a reasonable equity ratio, with Staff shifting some of the proposed capital structure from the Common Equity layer to Long-Term Debt.<sup>704</sup>

This PFD agrees with the Attorney General that the long-term debt balance should coincide with the allocation of the total permanent capital of \$5.5 billion to 50% long-term debt and 50% common equity. Thus, this PFD recommends the adoption of the Attorney General's long-term debt balance of \$2.749 billion.

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<sup>699</sup> 4 Tr 1613, Chart 1; Ex. A-14, Sch. D1..

<sup>700</sup> 4 Tr 1480; Ex. AG-22.

<sup>701</sup> Id.

<sup>702</sup> 4 Tr 1480-1481.

<sup>703</sup> 4 Tr 1613.

<sup>704</sup> 4 Tr 1613.

### **Other Debt Balances**

DTE, Staff and the Attorney General agree with the amounts outstanding to be used in DTE's proposed capital structure for short-term debt, deferred federal income taxes ("FITs"), and the Job Development Investment Tax Credit (JDITC).<sup>705</sup> Accordingly, DTE's short-term debt balance (\$184 million), deferred FITs balance (\$1.261 billion) and JDITC balance (\$0) are adopted.

### **Cost Rates**

#### **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 standards for establishing a fair rate of return for public utilities are set forth in 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; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. 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.<sup>706</sup>

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<sup>705</sup> Ex. A-14, Sch. D-1; 4 Tr 1613, Chart 1; Ex. AG-22.

<sup>706</sup> 262 U.S. at 692-693.

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. Thus, . . . 'regulation does not insure that the business shall produce net revenues.' . . . [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.<sup>707</sup>

These standards are established as a matter of constitutional law.<sup>708</sup> As such, the *Bluefield* and *Hope* standards are controlling.<sup>709</sup> Indeed, the balancing of the interests of the ratepayers and the utility's shareholders required by *Bluefield* and *Hope* have long been recognized by the Michigan Supreme Court. See *City of Detroit v. Michigan Public Service Commission*, 308 Mich 706, 14 N.W. 2d 784 (1944):

It is the duty of the Commission, under its statutory power, to fix a just and reasonable rate. This can be accomplished only by balancing the interest of public utility investors and the consuming public. *Federal Power Commission v. Hope Natural Gas Co.*, . . . .<sup>710</sup>

The public should not be required to pay rates that will yield an extraordinary profit to the utility and the stockholders of the utility on the other hand are at all times entitled to a fair return on their investment. . . .<sup>711</sup>

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<sup>707</sup> 320 U.S. at 603. Citations omitted.

<sup>708</sup> See, *Bluefield*, *supra* at 690 ("The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.").

<sup>709</sup> See *Michigan Public Utilities Commission v. Michigan State Telephone*, 228 Mich 658, 664, 200 N.W. 749 (1924)("These elements [of just compensation, including . . . a fair return upon the present value of the property used and useful in public service], when determined, measure the rate to be paid by the public for the service. Upon the issue of confiscation, a federal question, decisions of the Supreme Court of the United States are controlling.").

<sup>710</sup> 308 Mich at 716.

<sup>711</sup> 308 Mich at 718.

If the price of electricity can be reduced and still leave a reasonable return on the fair value of all property as required by [statute], then the commission has a duty to make such reduction in rates.<sup>712</sup>

Similarly, the Commission has long recognized the applicability of the *Bluefield* and *Hope* standards. See, e.g., Case No. U-5365, Opinion and Order, September 28, 1978, p. 24 (“The United States Supreme Court has established standards to measure the reasonableness of a rate of return on common equity established by a regulatory commission”, quoting *Bluefield* and *Hope, supra.*)<sup>713</sup> In addition, Commission has noted that the determination of what is fair and reasonable “is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use.”<sup>714</sup>

### **DTE**

Dr. Villadsen states that as DTE Gas’ requested 51.5% equity, she finds an overall range of 10.0% to 10.7% to be reasonable, and recommends that DTE Gas be allowed to earn a 10.25% rate of return.<sup>715</sup> She adds that based on her consideration of the capital estimation model results in the context of Michigan and DTE Gas specific risks, she asserts that it is appropriate and reasonable to place DTE Gas’ allowed return at 10.25%.<sup>716</sup>

Dr. Villadsen states that when estimating the cost of equity for a given asset or business venture, two categories of risk are important; business risk, which is the degree

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<sup>712</sup> 308 Mich at 715 (Dissent).

<sup>713</sup> Citations omitted.

<sup>714</sup> Case No. U-15244, Order, December 23, 2008, p. 12, citing *Meridian Twp. v City of East Lansing, Mich.*, 342 Mich 734, 749, 71 NW2d 234 (1955).

<sup>715</sup> 4 Tr 2449.

<sup>716</sup> Id.

to which the cash flows generated by the business (and its assets) vary in response to moves in the broader market, and financial risk, which depends on how the business enterprise is financed.<sup>717</sup> Dr. Villadsen states that higher degrees of debt in the capital structure amplify the variability in the expected rate of return earned by equity holders, such that a greater proportion of debt in the capital structure increases risk for equity holders, causing them to require a higher rate of return on their equity investment, even for an equivalent level of underlying business risk.<sup>718</sup>

Dr. Villadsen states that she considers the impact of any difference between the financial risk inherent in the CAPM and DCF cost of equity estimates for the proxy companies and the capital structures used to determine DTE Gas' required ROE.<sup>719</sup> She asserts that differences in financial risk due to the different degree of financial leverage in DTE Gas' regulatory capital structure compared to the capital structures of the proxy companies mean that the equity betas measured for the proxy companies must be adjusted before they can be applied in determining DTE Gas' CAPM ROE, and similarly, the cost of equity measured by applying the DCF models to the proxy companies' market data requires adjustment if it is to serve as an estimate of the appropriate allowed ROE for DTE Gas at the regulatory capital structure the Commission grants.<sup>720</sup> She argues that taking differences in financial leverage into account acknowledges the fact that a higher degree of financial leverage in the regulatory capital structure imposes a higher degree of financial risk for an equity investment in DTE Gas' rate base than is experienced by

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<sup>717</sup> 4 Tr 2451.

<sup>718</sup> 4 Tr 2453-2454.

<sup>719</sup> 4 Tr 2454.

<sup>720</sup> Id.

equity investors in the market-traded stock of the less leveraged proxy companies.<sup>721</sup> She states that to determine the cost of equity that is required at DTE Gas' capital structure, she estimates the overall cost of capital for each utility in the proxy group based on that utility's capital structure and then evaluates the average overall cost of capital across the proxy group.<sup>722</sup>

Dr. Villadsen states that one way to take the impact of financial risk into account is to determine the after-tax weighted-average cost of capital (ATWACC) for the proxy group using the equity and debt percentages as the weight assigned to the cost of equity and debt.<sup>723</sup> Dr. Villadsen states that she also used the Hamada approach, whereby she used the estimated beta to calculate what beta would be associated with a 100% equity financed firm to obtain a so-called all-equity or assets beta and then re-levered the beta to determine the beta associated with the regulatory capital structure.<sup>724</sup>

Dr. Villadsen states that her approach to estimating the cost of equity for DTE Gas focuses on measuring the expected returns required by investors to invest in companies that face business and financial risks comparable to those faced by DTE Gas.<sup>725</sup> Dr. Villadsen states that it is important that the Commission considers how "extreme market reactions to global events" may impact how easily capital will be able to be accessed should an "unforeseen market shock" occur.<sup>726</sup> Dr. Villadsen states that capital market conditions are important to cost of equity estimation methodologies and can affect the

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<sup>721</sup> Id.

<sup>722</sup> 4 Tr 2455.

<sup>723</sup> Id.

<sup>724</sup> Id.

<sup>725</sup> 4 Tr 2457.

<sup>726</sup> Id., quoting Case No. U-20697, Order, December 17, 2020, p. 165.

inputs to the cost of equity models.<sup>727</sup> She states that key factors such as Treasury, corporate and utility yields on debt instruments have increased, while measures of investors' perception of the risk premium they require to hold equity rather than debt has remained relatively constant.<sup>728</sup> She adds that inflation remains higher than in the recent past and high inflation is expected to remain at least into 2025.<sup>729</sup> She states that the risk of the utility industry (both electric and gas) as measured by the systematic risk (beta) has increased.<sup>730</sup> Thus, she asserts that the cost of equity is higher today than in the recent past.<sup>731</sup>

Dr. Villadsen states that to the extent that prevailing government yields are affected by monetary policy, and rising geopolitical tensions, using current yields as the risk-free rate would affect the CAPM estimate in a manner that may not reflect the forward looking cost of equity.<sup>732</sup> She adds that the allowed fair return on equity for DTE Gas should reflect the future interest rate environment at the time the rates being set in this proceeding will be in effect.<sup>733</sup>

Regarding bond yield spreads, Dr. Villadsen states that interest rates were at 1.49% at the time when DTE Gas' current ROE was authorized, and as a result of rising inflation and the subsequent monetary policy response by the Federal Reserve, government bonds have increased substantially since then, with interest rates on 10-year government bonds currently 321 basis points higher at 4.70%.<sup>734</sup> She adds that

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<sup>727</sup> 4 Tr 2460.

<sup>728</sup> 4 Tr 2460-2461.

<sup>729</sup> 4 Tr 2461.

<sup>730</sup> Id.

<sup>731</sup> Id.

<sup>732</sup> Id.

<sup>733</sup> Id.

<sup>734</sup> 4 Tr 2462.

professional forecasters and government agencies expect Treasury bond yields to remain relatively constant in the near-term and then decrease slightly over the next couple of years.<sup>735</sup> She states that *Blue Chip Economic Indicators (BCEI)* forecasts that the yield on 10-year Treasury bonds will average 4.0% in both 2023 and 2024, and that the 2023 and 2024 BCEI forecasts are about 70 basis points below the current 10-year Treasury bond yield (4.70%).<sup>736</sup>

Dr. Villadsen states that if both credit spreads and equity premiums are determined in part of the general premium required by investors for bearing systematic risk, then an increase in credit spreads may indicate an increase in the forward-looking market equity risk premium (“MRP”), which is a key input to the CAPM.<sup>737</sup> She adds that while presently the spread between 10-year BBB-rated utility bond yields and 10-year U.S. government bond yields is about 1.61%, as compared to this spread being 1.25% at the time of DTE Gas’ last rate case decision in December 2021, she did not take any portion of the elevated yield spread into account in her analysis.<sup>738</sup>

Dr. Villadsen states that measures of market volatility are slightly below long-term averages, noting that VIX is currently around 19.3, which is in-line with the long-run average of 19.6.<sup>739</sup> She adds that 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.<sup>740</sup> Thus, she concludes

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<sup>735</sup> Id.

<sup>736</sup> 4V Tr 2463. Citations omitted.

<sup>737</sup> 4 Tr 2464.

<sup>738</sup> Id.

<sup>739</sup> 4 Tr 2466. Citation omitted.

<sup>740</sup> Id.

that the evidence regarding investors' risk perception is mixed.<sup>741</sup>

Dr. Villadsen states the market risk premium ("MRP") is the risk premium associated with investing in the market as a whole.<sup>742</sup> She asserts that since the so-called "market portfolio" embodies the maximum possible degree of diversification for investors, the MRP is a highly relevant benchmark indicating the level of risk compensation demanded by capital market participants.<sup>743</sup> She adds that it is also a direct input necessary to estimating the cost of equity using the CAPM and other risk-positioning models.<sup>744</sup> She states that the majority of the evidence indicates an MRP somewhat above 7% or close to historical average MRP (7.17%).<sup>745</sup>

Dr. Villadsen states that the spread between BBB-rated utility bonds and 10-year Treasury bonds is currently about 1.61%, which is above the long-term historic average spread of 1.23%, prior to the financial crisis and which indicates that investors require a higher than historic premium to invest in assets that are not risk-free.<sup>746</sup> She adds that as equity is not risk-free and riskier than BBB-rated utility bonds, it indicates that the premium investors require to invest in equity is elevated.<sup>747</sup>

Dr. Villadsen states that the Federal Reserve forecasts that inflation will be elevated through at least 2025, which is also the expectations of *Blue Chip Economic Indicators* ("BCEI").<sup>748</sup> She adds that inflation has decreased to 3.2% in July 2023, increased in August 2023 to 3.7%, and remained at 3.7% in September 2023.<sup>749</sup> She

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<sup>741</sup> Id.

<sup>742</sup> Id.

<sup>743</sup> 4 Tr 2466-2467. Citation omitted.

<sup>744</sup> 4 Tr 2467.

<sup>745</sup> Id.

<sup>746</sup> Id.

<sup>747</sup> Id.

<sup>748</sup> 4 Tr 2468-2469. Citations omitted.

<sup>749</sup> 4 Tr 2469. Citation omitted.

states that recent surveys by economists, such as the *BCEI* survey, indicate that U.S. inflation will be 4.1% in 2023 and 2.7% in 2024.<sup>750</sup>

Dr. Villadsen states that she looked to a proxy group of regulated natural gas and water utilities to evaluate comparable business risk.<sup>751</sup> Dr. Villadsen states she selected two proxy groups consisting of publicly traded companies, one consisting of companies providing primarily regulated natural gas distribution services and the second consisting of highly regulated companies in the water utility industry.<sup>752</sup> She adds that she relied on the natural gas proxy group for her recommendation and used the water proxy group to test the reasonableness of the results from natural gas proxy group.<sup>753</sup>

Dr. Villadsen states that she analyzed and adjusted for differences in financial risk due to different levels of financial leverage among the proxy companies and between the capital structures of the proxy companies, and the regulatory capital structure that will be applied to DTE Gas for ratemaking purposes.<sup>754</sup> She adds that she compared the business risk of DTE Gas to that of the proxy group companies.<sup>755</sup>

Dr. Villadsen states that selecting companies with business operations concentrated in the regulated natural gas distribution industry or having similar lines of business and/or business environments is an appropriate starting point for selecting proxy groups of comparable risk to DTE Gas.<sup>756</sup> She adds that as a second step, she evaluated

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<sup>750</sup> 4 Tr 2470, citing Blue Chip Economic Indicators, October 10, 2023.

<sup>751</sup> 4 Tr 2453.

<sup>752</sup> Id.

<sup>753</sup> Id.; 4 Tr 2472. See, also, discussion, *infra*.

<sup>754</sup> Id.

<sup>755</sup> Id.

<sup>756</sup> 4 Tr 2472.

DTE Gas or Michigan-specific risks to ensure that DTE's ROE is placed appropriately relative to the sample companies.<sup>757</sup>

Dr. Villadsen states that in selecting her proxy group, she started with the universe of publicly traded companies on Value Lines' list of publicly traded companies classified as natural gas LDCs or water utilities.<sup>758</sup> She adds that she eliminated companies that had less than 50% of their assets dedicated to regulated utility activities in the natural gas or water utility service industries, eliminated companies that have had recent significant events that could affect the market data necessary to perform cost of capital estimation, required companies have an investment grade credit rating, and required the proxy companies have the necessary data available for estimation.<sup>759</sup> She states that her final natural gas proxy group consists of eight natural gas utilities, with credit ratings in the range of BBB- to A+, which she asserts is consistent with DTE Gas' A- issuer credit rating from S&P.<sup>760</sup>

Dr. Villadsen states that she derived cost of equity estimates from two versions of the CAPM -- the traditional version and an alternative version (ECAPM).<sup>761</sup> She states that she also used a single-stage and a multi-stage version of the DCF, and an risk-premium model that serves as a check on the reasonableness of her market-based results.<sup>762</sup> Dr. Villadsen states that FERC relies on versions of the DCF and CAPM as

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<sup>757</sup> Id.

<sup>758</sup> 4 Tr 2473-2474.

<sup>759</sup> 4 Tr 2474. Citation omitted. She notes that Chesapeake Utilities does not have a credit rating from any of the major rating agencies, and thus that she assigned the company the average credit rating of the rest of the proxy group. In addition, she notes that New Jersey Resources and Northwest Natural are not rated by S&P, however she used the credit rating of their major utility subsidiaries (New Jersey Natural Gas Co. and Northwest Natural Gas Co.). Id., n. 59.

<sup>760</sup> 4 Tr 2475-2476, Figure 9. Citation omitted.

<sup>761</sup> 4 Tr 2478, 2482.

<sup>762</sup> 4 Tr 2457.

well as the implied Risk Premium method in its determination of just and reasonable ROEs for transmission owners.<sup>763</sup>

Dr. Villadsen states that the CAPM states that the cost of capital for an investment is determined by the risk-free rate plus the stock's systematic risk (as measured by beta) multiplied by the market risk premium ("MRP").<sup>764</sup> For her CAPM, Dr. Villadsen states she used the forecasted yield on a 20-year U.S. Treasury bond in 2024 and 2025 (3.95%) as the risk-free asset.<sup>765</sup> For the MRP, she used an historical average market risk premium from 1926 to the present (December 2022), which is 7.17% and which she considered more reasonable than Bloomberg's forward-looking MRP estimate of 5.72% which she asserts underestimates the cost of equity.<sup>766</sup> She states that she used Value Line betas.<sup>767</sup>

Dr. Villadsen states that because DTE Gas regulatory capital structure includes a higher proportion of debt financing compared to the proxy companies market value capital structures, the financial risk associated with an equity investment in DTE Gas rate base is correspondingly greater than the financial risk borne by investors in the proxy companies' publicly traded stock.<sup>768</sup> Thus, she used the Hamada technique -- unlever the Value Line betas and relever the resulting asset betas at DTE Gas' regulatory capital structure -- to account for the impact of different financial leverage on financial risk.<sup>769</sup> She calculates her CAPM and ECAPM ROE estimates using two market risk premiums - 7.17% and 5.72% -- and asserts that the 7.17% MRP deserves the most weight because

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<sup>763</sup> 4 Tr 2458, citing FERC Order 569-A.

<sup>764</sup> 4 Tr 2478.

<sup>765</sup> 4 Tr 2479. Dr. Villadsen states that she averaged two 10-year bond yield projections, and then adjusted upward by 50 basis points to estimate the representative historical maturity premium for the 20-year over the 10-year Government Bond. V Tr 34-35.

<sup>766</sup> 4 Tr 2480-2481, 2482.

<sup>767</sup> 4 Tr 2481.

<sup>768</sup> Id.

<sup>769</sup> Id., n. 76; 4 Tr 2484.

the forward-looking MRP from the FERC methodology is comparable to the historical MRP she used.<sup>770</sup> She also uses the 20-year Treasury bond yield as a measure of the risk-free asset, which she calculates as 3.95%.<sup>771</sup>

Regarding ECAPM, Dr. Villadsen asserts that empirical research has shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher risk premiums than predicted by the CAPM and high-beta stocks tending to have lower risk premiums than predicted. As such, Ms. Villadsen also calculated an ROE estimate using ECAPM, which involves using beta to measure relative risk by making a direct empirical adjustment to the CAPM.<sup>772</sup> She adds that while she reports results from the “Financial Risk Adjusted Method” in the workpapers, she ignores these results in her assessment because the Commission in the past has been critical of the approach.<sup>773</sup>

Dr. Villadsen’s ROE estimates for the gas proxy group are as follows: a) CAPM (historical MRP) 11.0% - 11.2%; CAPM (forward-looking MRP) 9.5% - 9.7%; ECAPM (historical MRP) 11.0% - 11.2%; ECAPM (forward-looking MRP) 9.6% - 9.7%.<sup>774</sup>

Regarding the DCF model, Dr. Villadsen states that this model attempts to estimate the cost of capital for a given company directly, and assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive.<sup>775</sup> She adds that there are different versions of the DCF model including the

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<sup>770</sup> 4 Tr 2482; 2484, Figure 13.

<sup>771</sup> 4 Tr 2480-2481; Appx. B, p. 6-7. Citation omitted.

<sup>772</sup> 4 Tr 2482-2483.

<sup>773</sup> 4 Tr 2485, n. 80.

<sup>774</sup> 4 Tr 2484, Figure 13. Dr. Villadsen notes that the average ROE estimated for the gas proxy group using the CAPM and ECAPM with the historical MRP are 10.1% and 10.3%, respectively, before any consideration of financial risk, while adding that she does not agree with these results. 4 Tr 2485, n. 83.

<sup>775</sup> 4 Tr 2485.

single-stage model and multi-stage models.<sup>776</sup> She calculates an estimated ROE using both a single-stage and a multi-stage model, stating that for her multi-stage model she assumed that companies grow their dividend for five years at the forecasted company-specific rate of earnings growth, with that growth then tapering over the next five years toward the growth rate of the overall economy.<sup>777</sup> She adds that the multi-stage DCF model likely understates the cost of equity as it is plausible the payout ratio changes and a company reaches steady-state growth.<sup>778</sup>

Dr. Villadsen states that for the single-stage DCF and for the first stage of the multi-stage DCF, she used investment analyst forecasts of company-specific growth rates sourced from *Value Line* and Thomson Reuters *IBES*, and for the long-term growth rate for the final, constant-growth stage of the multistage DCF estimates, she used the long-term nominal U.S. GDP growth forecast of 3.9% from *Blue Chip Economic Indicators*.<sup>779</sup> She states that the DCF results for the gas proxy group were 11.1% for the single-stage model and 9.0% for the multi-stage model.<sup>780</sup> She argues that because the forecasted long-term GDP growth rate is low, which she asserts may be a result of the perception that growth may slow in the near-term due to high financing costs or a possible slowdown in the economy, the single-stage DCF calculation merits more weight than the multi-stage DCF.<sup>781</sup>

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<sup>776</sup> 4 Tr 2486.

<sup>777</sup> 4 Tr 2487.

<sup>778</sup> Id.

<sup>779</sup> Id. Citation omitted.

<sup>780</sup> 4 Tr 2488, Figure 14. Dr. Villadsen notes that the average ROE estimated for the gas proxy group using the single-stage DCF is 10.3% before any consideration of financial risk, adding that she does not agree with the result. 4 Tr 2489, n. 88.

<sup>781</sup> 4 Tr 2489.

Dr. Villadsen states that for the risk premium model, the cost of equity capital for utilities is estimated based on the historical relationship between allowed ROEs in utility rate cases and the risk-free rate of interest at the time the ROEs were granted.<sup>782</sup> Using the rate case data from 1990 through August 2023 derived from S&P Capital IQ's Regulatory Research Associates ("RRA"), she compared the average allowed rate of return on equity granted by U.S. state regulatory agencies in natural gas LDC cases to the average 20-year Treasury bond yield that prevailed in each quarter.<sup>783</sup> She states that her risk premium model estimates an ROE of 10.2%, while using a risk-free rate of 3.95%.<sup>784</sup>

Dr. Villadsen states that while the risk premium model is based on historical allowed returns and not underpinned by fundamental financial principles in the manner of the CAPM and DCF models, she asserts that this analysis is a valid and useful approach to estimating utility ROEs.<sup>785</sup> She adds that because the risk premium analysis as implemented takes into account the interest rate prevailing during the quarter the decision that granted an ROE used in the analysis was issued, it provides a useful benchmark for the cost of equity in any interest rate environment.<sup>786</sup> She states that because it relies on the returns for regulated utilities, this method provides a good way to assess directly whether the ROE is commensurate with that available to alternative regulated investments of similar risk.<sup>787</sup>

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<sup>782</sup> Id.

<sup>783</sup> 4 Tr 2490.

<sup>784</sup> 4 Tr 2490-2491, Figure 15. Dr. Villadsen states that she relied on the 20-year government bond to be consistent with the analysis using the CAPM.

<sup>785</sup> 4 Tr 2491.

<sup>786</sup> Id.

<sup>787</sup> Id.

In summary, Dr. Villadsen states that, taking the average of the low and high estimates, she finds a range of approximately 10.0% to 10.7% for a midpoint of 10.35%.<sup>788</sup> Noting that the Commission in the past has raised concerns about the financial risk consideration, she states that the average of the single-stage DCF result before any financial risk consideration is 10.3% and the average of the CAPM results before any financial risk considerations is 10.1%, when the historical MRP is used.<sup>789</sup>

Dr. Villadsen states that DTE Gas is engaged in similar line of business, has comparable credit ratings and has access to alternative regulatory mechanisms, and similar to most natural gas utilities, DTE Gas is facing increasing risk from state decarbonization policies.<sup>790</sup> She adds that DTE Gas has higher operating leverage than the natural gas proxy group.<sup>791</sup> She concludes that she considers DTE Gas' business risk to be above the average compared to the proxy samples' risk profile.<sup>792</sup> As DTE Gas is not requesting a return on equity above the midpoint of her estimated range, she does not quantify the magnitude by which DTE Gas' risk exceeds that of the average of the Gas proxy group.<sup>793</sup>

Dr. Villadsen states that a range of about 10.0% to 10.7% with a midpoint of 10.35% is reasonable for the gas proxy group, and based upon her review of DTE Gas' business risk profile relative to the proxy companies, she recommends that DTE Gas be placed near the midpoint of the reasonable range.<sup>794</sup> She adds that if a lower than 51.5%

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<sup>788</sup> Id.

<sup>789</sup> 4 Tr 2491-2492.

<sup>790</sup> 4 Tr 2495.

<sup>791</sup> Id.

<sup>792</sup> Id. .

<sup>793</sup> Id.

<sup>794</sup> Id.

equity is allowed for DTE Gas, then its cost of equity is higher than the 10.25% she recommends at 51.5% equity.<sup>795</sup>

### **Staff**

Mr. Ufolla states that Staff recommends a return on equity of 9.80%, which is the midpoint of Staff's 9.30% - 10.30% ROE range.<sup>796</sup>

Mr. Ufolla states that to determine a fair ROE, and since DTE Gas isn't publicly traded, he used a group of eight publicly traded gas utility companies as a comparable proxy group for Staff's analysis.<sup>797</sup> He states that 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, and that a Risk Premium model and a review of gas ROE authorizations from other state jurisdictions from 2022-2023 are also utilized in this case.<sup>798</sup> He adds that Staff's 9.80% recommendation considers DTE's currently authorized 9.90% and requested 10.25% ROE in the instant case.<sup>799</sup>

Mr. Ufolla states that when considering a return on equity recommendation for a utility company, Staff takes into consideration the landmark Supreme Court decisions in the *Hope* and *Bluefield* cases.<sup>800</sup> He adds that no one methodology provides an exact measure of a fair rate of return on equity, and that the DCF method and the CAPM Model are the primary models most utility financial analysts use in rate cases to determine a fair and reasonable cost of equity for regulated utility companies.<sup>801</sup>

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<sup>795</sup> 4 Tr 2496.

<sup>796</sup> 4 Tr 1619.

<sup>797</sup> Id.

<sup>798</sup> 4 Tr 1619-1620.

<sup>799</sup> 4 Tr 1619.

<sup>800</sup> 4 Tr 1620.

<sup>801</sup> 4 Tr 1621.

Mr. Ufolla states that Staff's proxy group consists of eight gas companies that meet four criteria: the company must 1) be listed as an Gas Utility by Value Line, 2) have a full Value Line report available, 3) be currently paying dividends to shareholders, and 4) not be the target of a merger or acquisition.<sup>802</sup> He adds that typically, Staff would also consider other factors such as credit rating and foreign investment, but that due to the limited number of proxy candidates for this case, Staff has included both Chesapeake Utilities and UGI Corp for this case, the inclusion of which did result in nominally higher outputs from the CAPM and DCF analyses.<sup>803</sup>

Mr. Ufolla states that Staff's proxy group is similar to DTE's proxy group with UGI Corp in place of Southwest Gas Holdings.<sup>804</sup> He adds that Staff chose to not include Southwest Gas in its proxy group due to its separation from Centuri Group which may have caused short term variations in stock price.<sup>805</sup> He states that Dr. Villadsen also presented a proxy group of water utilities which Staff has disregarded because water utilities do not face the same risks as gas utilities and because Dr. Villadsen states her ROE recommendation only relies on her gas proxy.<sup>806</sup>

Regarding Staff's DCF analysis, Mr. Ufolla states that Staff uses the closing stock prices from December 2023, January 2024, and February 2024 along with the most recent quarterly dividend to calculate the annual dividend yields for the proxy group.<sup>807</sup> He adds that the dividend yield is modified by the semi-annual compounding method, which he asserts is the preferred model to use when performing a DCF analysis on a

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<sup>802</sup> Id.

<sup>803</sup> 4 Tr 1621-1622.

<sup>804</sup> 4 Tr 1622.

<sup>805</sup> Id.

<sup>806</sup> Id. Citation omitted.

<sup>807</sup> 4 Tr 1623; Ex. S-4, Sch. D-5.

group of comparison companies, and is the preferred method used by the Federal Energy Regulatory Commission (FERC).<sup>808</sup> He states that for growth rates, Staff employs three well-known and widely used sources, Yahoo Finance, Zacks, and Value Line, with the average of these sources is used to determine each individual proxy company's growth estimate.<sup>809</sup> He adds that all available growth rate data is utilized ranging from 2.8% to 9.50%.<sup>810</sup> He asserts that Staff arrived at an average adjusted DCF cost of equity estimate of 10.51%, and a median adjusted DCF cost of equity estimate of 10.01%, while noting that when excluding Chesapeake and UGI, the average is 10.33% and the median is 10.01%.<sup>811</sup>

Mr. Ufolla states that he disagrees with DTE's DCF analysis and the ROE results from it.<sup>812</sup> Noting Dr. Villadsen's use of the After-Tax Weighted Average Cost of Capital (ATWACC) approach, he asserts that that approach has never been approved by the Commission, it will most always require a higher cost of equity, and it is a tool that does not analyze the Cost of Equity exclusively as a pure DCF or CAPM equation is designed to do.<sup>813</sup>

Regarding Staff's CAPM analysis, Mr. Ufolla states that the data Staff reviewed -- the S&P 500 return from Damodaran for a return on stocks and a mixture of data from Kroll and the Federal Reserve Database for long-term government bond yields -- results in an average historical risk premium of 6.80% from 1928-2023.<sup>814</sup> Noting that that the

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<sup>808</sup> 4 Tr 1623-1624. Citation omitted.

<sup>809</sup> 4 Tr 1624.

<sup>810</sup> Id.

<sup>811</sup> Id., n. 11.

<sup>812</sup> Id.

<sup>813</sup> 4 Tr 1624-1625.

<sup>814</sup> 4 Tr 1626.

risk-free rate used in the CAPM analysis is the yield associated with a long-term 30-year U.S. government Treasury bond, Mr. Ufolla adds that Staff reviewed projections of 2024 and 2025 Treasury bond yields from IHS Markit over a three-month period, with the average projection weighted to match the test year being 3.81%.<sup>815</sup> He states that Staff uses beta values from Value Line, which is a forward-looking beta, which measures a 60-month average raw beta on a weekly basis and adjusts that raw beta by a convergence factor towards the market.<sup>816</sup> Mr. Ufolla concludes that utilizing a risk-free rate of 3.81%, a historical risk premium of 6.80%, and an average beta of 0.89, Staff computes an average CAPM cost of equity of 9.88%.<sup>817</sup>

Mr. Ufolla states that Staff does not agree with DTE's methodology for the CAPM models.<sup>818</sup> He adds that Staff does not agree with the use of the Hamada Adjustment, as Staff does not believe it is appropriate to make an adjustment for equity ratio of the proxy companies in a ratemaking environment.<sup>819</sup> He asserts that Staff rejects the Hamada method because there is a fundamental difference between the debt to equity ratio of a publicly traded parent company (like those found in the proxy group) who's equity balance is calculated based on its market value, and a privately owned utility (like DTE Gas) who's equity balance is determined based on its book value.<sup>820</sup> He argues that when removing Dr. Villadsen's Hamada adjustment from the equation, her average CAPM estimates for the electric [sic] proxy under scenario 1 is 10.09% and under scenario 2 is 8.84%.<sup>821</sup> He

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<sup>815</sup> 4 Tr 1627.

<sup>816</sup> Id.

<sup>817</sup> 4 Tr 1627-1628; Ex. S-4, Sch. D5. He notes that if Chesapeake and UGI are excluded, the CAPM average is 9.77%. Id., n. 12.

<sup>818</sup> Id.

<sup>819</sup> Id.

<sup>820</sup> 4 Tr 1628.

<sup>821</sup> 4 Tr 1629.

notes that the Scenario 2 models use a forward looking market risk premium of 5.72% from Bloomberg, which is lower than Staff's preferred historical market risk premium and therefore the results are below those yielded by Staff's analysis.<sup>822</sup> He adds that without the Hamada adjustment, the alpha adjustment of the ECAPM makes a larger difference and Staff would not recommend relying on this model.<sup>823</sup>

Regarding its risk premium analysis, Mr. Ufolla states that 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.<sup>824</sup> He adds that essentially this analysis looks at the historical risk premium investors have received for choosing to invest in the equity of a utility company as opposed to a utility bond or Treasury bond.<sup>825</sup> He states that Staff reviews the Gas Utility Realized Market Return Average from 1955 through 2023, compares it with the A-Rated Public Utility Bond Yield Average, or Treasury bond yield, over the same period.<sup>826</sup> He asserts that the average gas utility market return over the period was 10.88%, the average return of an A-rated composite utility bond was 7.16%, the average Treasury yield was 5.71% over the same period, and that adding the risk premiums with the current yields results in an estimate of 9.08% using the A-rated utility bond method and 8.97% using the Treasury bond method.<sup>827</sup> He adds that current Baa-rated utility bond yield of 5.63% were also added to the utility bond premium for a result of 9.34%, which results in a higher

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<sup>822</sup> 4 Tr 1629-1630.

<sup>823</sup> 4 Tr 1629.

<sup>824</sup> 4 Tr 1630.

<sup>825</sup> Id.

<sup>826</sup> Id.; Ex. S-4, Sch. D5.

<sup>827</sup> Id.

cost of equity estimation due to the fact that a Baa-rated bond will have a lower risk premium.<sup>828</sup>

Mr. Ufolla states that he disagrees with DTE's risk premium analyses. He notes that Dr. Villadsen uses a regression analysis in her risk premium model, while Staff prefers the use of a more traditional risk premium model that is more widely accepted in the ratemaking process, and that because she employs the use of approved ROE instead of earned ROE (like Staff's model), Dr. Villadsen's data set only reaches back to 1992.<sup>829</sup> For these reasons, Staff maintains its preference for its own Risk Premium models that have a larger data set, and basis in earned ROE.<sup>830</sup>

Mr. Ufolla states that Staff reviewed authorized rate of return decisions for gas utilities rendered by other state commissions across the country for 2022 and 2023, with the average authorized ROE decisions for 2022 being 9.53%, and the average in 2023 being 9.64%.<sup>831</sup>

Mr. Ufolla summarizes Staff's cost of equity estimates and Staff's recommendation of an ROE range of 9.30% - 10.30% and Staff's recommendation of an ROE of 9.80% which he asserts is the midpoint of Staff's range.<sup>832</sup>

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<sup>828</sup> 4 Tr 1630-1631.

<sup>829</sup> 4 Tr 1631.

<sup>830</sup> Id.

<sup>831</sup> 4 Tr 1631-1632, citing S&P Global: RRA Regulatory Focus Major Rate Case Decisions (Ex. S-4 Sch. D-5, p. 11).

<sup>832</sup> 4 Tr 1632, Chart 4. This PFD notes that Staff's DCF and CAPM ROE ranges shown in Chart 4 do not correlate to Mr. Ufolla's testimony regarding his DCF and CAPM model results, nor to Mr. Ufolla's DCF and CAPM calculation exhibits. See 4 Tr 1624, Ex. S-4, Sch. D-5, p. 5; U Tr 19-20, Ex. S-4, Sch. D-5, p. 6.

## Attorney General

Mr. Coppola recommends an overall after-tax return on capital of 5.82%, which includes a return on common equity of 9.85%.<sup>833</sup>

Mr. Coppola states that a utility company is entitled to a fair return that will allow it to attract capital and be sufficient to assure investors of its financial soundness, per *Bluefield Water Works v Public Service Commission*, 262 U.S. 679 (1923), and *FPC v Hope Natural Gas Company*, 320 U.S. 591 (1944).<sup>834</sup> He adds that he used three methods to determine the cost of equity: the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and the Utility Risk Premium approach.<sup>835</sup> He adds that he also considered the circumstances in the Capital Markets in 2023 and early 2024 and any potential changes in the risk profile of DTE Gas and the economy in the state of the Michigan.<sup>836</sup> He states that while Exhibit AG-23 shows a weighted average cost of common equity of 9.81% using the three methods, he recommends an authorized rate of return on equity of 9.85%.<sup>837</sup>

For his peer group, Mr. Coppola started with the nine gas utility companies followed by the Value Line Investment Survey in its “Natural Gas Utility Industry” section, and he removed UGI Corporation due to its foreign investments and propane investments, which is 50% of its business; and (2) Southwest Gas Holdings, which has announced that it will either sell or spin-off its large infrastructure unit — Centuri.<sup>838</sup> He states that he added Black Hills Corporation (Black Hills), which is classified by Value

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<sup>833</sup> 4 Tr 1492, Ex. AG-22.

<sup>834</sup> 4 Tr 1493.

<sup>835</sup> 4 Tr 1494.

<sup>836</sup> Id.

<sup>837</sup> Id.; Ex. AG-23.

<sup>838</sup> 4 Tr 1494-1495.

Line as an electric utility but which derives approximately 50% of its earnings from natural gas distribution, resulting in eight companies all of which have growing earnings and dividends.<sup>839</sup> He adds that Dr. Villadsen's proposed peer group is inappropriate, as including the nine water companies is not necessary and four of the nine water companies selected by witness Villadsen are small entities with annual revenues of approximately \$200 million or less in comparison to DTE's reported revenue of \$1.7 billion for 2023.<sup>840</sup>

Mr. Coppola states that DTE has included these water utility companies in its rate cases in recent years, while noting that in DTE's most recent fully contested rate case, the Commission stated that the inclusion of water utilities and the use of ATWACC and the Hamada approach were all inappropriate.<sup>841</sup> He adds that there are significant structural differences between gas utilities and water companies, asserting that gas companies are subject to volatility in natural gas prices, state mandated energy conservation programs, and the risk of gas explosions, while water utilities do not face the same water supply price volatility, and with the exception of arid areas on the west coast, do not have state mandated water conservation programs or similar risks as gas utilities.<sup>842</sup>

Mr. Coppola concludes that the Commission should reject DTE's peer groups which include water utilities and Southwest Gas Holdings due to its pending divestiture of its pipeline construction business.<sup>843</sup>

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<sup>839</sup> 4 Tr 1495; Ex. AG-24.

<sup>840</sup> 4 Tr 1495-1496.

<sup>841</sup> 4 Tr 1496, quoting Case No. U-20940, Order, December 9, 2021, p. 91.

<sup>842</sup> 4 Tr 1497.

<sup>843</sup> Id.

Regarding his DCF analysis, Mr. Coppola states the stock price information reflects the average of the high and low prices for each of the equity securities on each of the 30 trading days from February 15, 2024 March 31, 2024, the annual dividend is the projected average annual dividend level for the 2024-2025 period as projected by the Value Line Investment Survey, and the average long-term earnings growth rate is based on Value Line projections of earnings per share through the year 2028 and Yahoo Finance analysts' projected growth over the next five years.<sup>844</sup> He states that the resulting calculation of the DCF Method indicates an average required return on common equity of 9.51% for the proxy group.<sup>845</sup> He notes that his result is lower than DTE's "simple" DCF study result for the gas group of 11.1%, but comparable to DTE's "multi-stage" DCF result of 9.02% calculated Dr. Villadsen.<sup>846</sup>

Mr. Coppola states that the key differences between his 9.5% DCF cost of capital and Dr. Villadsen's DCF estimate for the gas group at 11.1% are (a) the growth rates utilized, which bring the outcome to 10.3%; and (b) the ATWACC process, which increases the result further to 11.1%.<sup>847</sup> He adds that the growth rates she uses average to 6.6%, which was determined in the later part of 2023, while his DCF average growth rate of 5.4% was developed in April 2024, and is 120 basis points lower than DTE's growth rate.<sup>848</sup> He states that the inclusion of Southwest Gas Holdings with a higher growth rate contributes to the higher outcome in DTE's calculations, and that Dr. Villadsen's pre

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<sup>844</sup> 4 Tr 1498-1499; AG-24.

<sup>845</sup> 4 Tr 1499.

<sup>846</sup> Id.

<sup>847</sup> Id.

<sup>848</sup> Id.

ATWACC DCF cost of capital for her gas group is 10.3%, as the ATWACC calculations inflate the DCF ROE rate to 11.1%.<sup>849</sup>

Regarding Dr. Villadsen's use of the ATWACC approach, Mr. Coppola states that the key driver in this complex process of calculations is the ratio by which the stock market equity exceeds book value equity, whereby this process of determining the After-Tax Weighted Average Cost of Capital is simply a mathematical process to drive an upward adjustment of the final ROE rate using stock market premiums over book equity values.<sup>850</sup> He adds that the resulting effect of this ATWACC approach is that higher market to book ratios in the utility industry (due to lower interest rates and other factors), if embraced by regulatory commissions, would lead to higher ROEs awarded in rate cases and a form of future bonus earnings for achieving higher stock prices for utility investors.<sup>851</sup> He states that the Commission should recognize the inherent circularity of the ATWACC process, in that if the ATWACC approach was to become universally embraced by regulatory commissions, the ROEs awarded in regulatory proceedings would increase, whereby the inflated ROEs would result in higher utility earnings, stock prices, and higher market to book ratios for utility common stocks, and the subsequent calculated ROEs in new rate cases under the ATWACC method would then produce even higher awarded ROEs because the ATWACC would use the higher stock market equity capitalization.<sup>852</sup> He adds that DTE does not cite any state regulatory commissions in the U.S. that have

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<sup>849</sup> Id.

<sup>850</sup> 4 Tr 1500.

<sup>851</sup> 4 Tr 1500-1501.

<sup>852</sup> 4 Tr 1501.

adopted this methodology for purposes of setting an authorized ROE in a utility rate case.<sup>853</sup>

Regarding his CAPM analysis, Mr. Coppola states that his results of the CAPM method based upon (1) a projected 30-year U.S. Treasury bond rate; (2) Beta information available from Value Line; and (3) Historical Market Risk Premium information of 7.17% based on the Ibbotson Classic Yearbook through 2022.<sup>854</sup> He states that he added the peer group risk premium of 6.32% to the 4.1% risk-free rate to arrive at the 10.42% ROE rate under the CAPM method.<sup>855</sup> He adds that while CAPM has value in assessing the relative risk of different stocks or portfolios of stocks, the key issue with CAPM is that it assumes that the entire risk of a stock can be measured by the “Beta” component and as such the only risk an investor faces is created by fluctuations in the overall market.<sup>856</sup> He asserts that in actuality, investors take into consideration company-specific factors in assessing the risk of each particular security, and as such, he gives the CAPM approach less weight than the DCF approach in determining the cost of common equity.<sup>857</sup>

Mr. Cappola states that Dr. Villadsen presents four different CAPM cost of equity estimates and four different ECAPM estimates for her gas sample companies, but notes that all of the estimates have been determined utilizing the Hamada Adjustment process with non-standard betas, which method provides faulty and inflated results.<sup>858</sup> As such,

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<sup>853</sup> Id.

<sup>854</sup> 4 Tr 1503; Ex. AG-25.

<sup>855</sup> Id.

<sup>856</sup> 4 Tr 1504.

<sup>857</sup> Id.

<sup>858</sup> Id.

he asserts that the Commission should not rely upon any of these CAPM or ECAPM results.<sup>859</sup>

Mr. Coppola states that Dr. Villadsen uses her data inputs and Value Line betas to develop her basic CAPM estimates of 10.1% and 8.8% for her gas group sample estimates, which results and inputs he asserts are reasonable.<sup>860</sup> He adds that what is not reasonable is the use of the Hamada approach with which she derives a non-standard beta of approximately 1.0, which is approximately 18% higher than her average Value Line beta average of 0.85 and which leads to the higher CAPM ROE outcome at 11.2% under her Scenario 1.<sup>861</sup>

Mr. Coppola states that the ECAPM is not widely accepted as a cost of equity methodology among gas and electric regulatory commissions in the United States.<sup>862</sup> He adds that the use of the 30-year treasury rate (not short-term rates) as the risk-free rate in the CAPM method resolves the need to use the ECAPM method and the inflated results that it produces.<sup>863</sup>

Mr. Coppola states that Dr. Villadsen's methods used to calculate the cost of equity capital are highly unconventional and not generally accepted.<sup>864</sup> As such, he asserts that the Commission should reject these alternative approaches because they are clearly a brazen attempt to inflate DTE's true cost of common equity in this case.<sup>865</sup>

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<sup>859</sup> Id.

<sup>860</sup> 4 Tr 1505; Ex. A-14, Sch. D5.10 and D5.11.

<sup>861</sup> Id.

<sup>862</sup> 4 Tr 1506.

<sup>863</sup> Id.

<sup>864</sup> Id.

<sup>865</sup> Id.

Regarding his utility risk premium approach, Mr. Coppola states one can estimate the cost of common equity by estimating and adding the following 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; and (3) the average return differential of utility common stocks over utility bonds.<sup>866</sup> He states that he used the historical spread of gas utility common stock returns relative to utility bonds of 4.05%, a 1.67% average spread for utility bonds (A rated and BBB rated) over the 30-year U.S. Treasury bond rate, and for the risk-free rate, used the projected 30-year Treasury rate of 4.1%.<sup>867</sup> His results for this approach reflect a return on common equity of 9.82%.<sup>868</sup>

Mr. Coppola states that despite higher interest rates, the economy remains strong, and that inflation has receded from approximately 8.5% in early 2022 to approximately 3% in recent months.<sup>869</sup> He adds that lower inflation and gas prices should benefit DTE in the projected test year and further interest rate decreases are expected should inflation reach nearer to the Federal Reserve Bank's 2% target.<sup>870</sup> He asserts that DTE's access to the capital markets and for its sister company, DTE Electric, is strong as shown by (1) DTE Gas issuing \$295 million of 7-year and 12-year long term debt with rates ranging from 5.57% to 5.73% in October 2023; and (2) DTE Electric issuing \$2.9 billion of 5-year to 30-year long-term debt at rates ranging from 5.57% to 5.73% at various times in

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<sup>866</sup> 4 Tr 1507.

<sup>867</sup> Id.; Ex. AG-26.

<sup>868</sup> Id.

<sup>869</sup> 4 Tr 1508.

<sup>870</sup> Id.

2023.<sup>871</sup> He adds that DTE's senior secured debt is rated at A/A1 and its commercial paper program is rated P-2 by Moody's Investor Service.<sup>872</sup>

Accordingly, Mr. Coppola argues that DTE's recommendation that the authorized rate of return on common equity should be increased to 10.25% to continue to have access to capital markets is unsupported by the evidence.<sup>873</sup> He adds that the results of his DCF analysis, CAPM analysis, and Utility Risk Premium Approach point to a calculated cost of equity closer to 9.81%, which he has rounded up to 9.85%.<sup>874</sup>

Regarding equity rates that other regulatory commissions have granted in 2022 and 2023, Mr. Coppola states that the majority of the 33 ROE decisions in 2022 and 36 decisions in 2023 are at rates well below 9.9%.<sup>875</sup> He adds that only two decisions in 2022 and 3 decisions in 2023 are at rates of 9.9% or greater, with these higher rates being from California, Florida, and Michigan.<sup>876</sup> He asserts that ROEs in California have been over 10%, reflecting the unique challenges of that state (wildfires and earthquakes), and the decisions in Florida pertain to smaller utility companies.<sup>877</sup> He asserts that for most of the other gas utilities that have business and financial risks comparable to DTE Gas, the ROE rates have averaged around 9.50% in the past two years, which supports his proposed ROE rate of 9.85%, and makes DTE's current ROE rate of 9.90% somewhat excessive and DTE's proposed ROE rate of 10.25% even further removed from reality and clearly unsupportable.<sup>878</sup>

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<sup>871</sup> Id.

<sup>872</sup> Id.

<sup>873</sup> Id.

<sup>874</sup> Id.

<sup>875</sup> 4 Tr 1509; Ex. AG-29.

<sup>876</sup> Id.

<sup>877</sup> Id.

<sup>878</sup> Id.

Mr. Coppola states that the Commission should not be concerned that establishing an authorized ROE of 9.85% in this case will lead to impairment of DTE's ability to access capital markets.<sup>879</sup> He adds that several gas utilities have accessed the capital markets at competitive interest rates since receiving a ROE near or below the average rate of 9.50%.<sup>880</sup> He states that there is no evidence equity investors have abandoned utilities that have been granted ROEs below 9.9%.<sup>881</sup> He asserts that stock investors continue to migrate to utility stocks, recognizing that authorized ROEs are still above the true cost of equity, as evidenced many of the peer group companies have received rate orders during the past few years reflecting ROEs as low as 9.3, while this group of companies has an average Market to Book common equity value ratio of nearly 1.5 times.<sup>882</sup>

Mr. Coppola states 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 Gas, as other gas utilities face the same issues and are able to raise capital with ROEs of 9.85% or below.<sup>883</sup>

Mr. Coppola states that market volatility should not be a concern in establishing a fair ROE rate for DTE.<sup>884</sup> He asserts that the stock market has historically been very volatile and in some periods, stock prices move up and down more dramatically than at other times.<sup>885</sup> Noting that Dr. Villadsen references the VIX index, which measures the 30-day implied volatility of the S&P 500 index, he states that in setting ROE rates for

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<sup>879</sup> Id.

<sup>880</sup> 4 Tr 1509-1510; Ex. AG-29.

<sup>881</sup> 4 Tr 1510.

<sup>882</sup> Id.; Ex. AG-28.

<sup>883</sup> Id.

<sup>884</sup> 4 Tr 1510-1511.

<sup>885</sup> 4 Tr 1511.

utilities, the Commission's focus is the long-term financial health of the utility not the short-term gyrations of the stock market.<sup>886</sup> He points to a Value Line Funds article written by Mitchell Appel, President of Value Line Funds in which Mr. Appel states that volatility is not risk.<sup>887</sup> Mr. Coppola states that utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market.<sup>888</sup> He adds that this is shown in the average Beta value of 0.88 of the utility peer group in contrast with the general stock market value of 1.<sup>889</sup>

Mr. Coppola states that the range of returns for the industry peer group from the three methods he used is from 9.51% at the low end, using the DCF approach and 10.42% at the high end using the CAPM approach.<sup>890</sup> He adds that he gives 50% weight to the DCF method as a more reliable approach to estimating the cost of equity, calculating 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 average cost of common equity of 9.81% which he has rounded upward to 9.85%.<sup>891</sup>

Mr. Coppola states that If the Commission were to grant a 9.90% ROE in this case versus a 9.85% ROE, the additional cost to customers is approximately \$2.1 million annually.<sup>892</sup> He argues that there is absolutely no need to burden customers with this additional cost, when historically DTE has been earning well above its true cost of common equity.<sup>893</sup>

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<sup>886</sup> Id.

<sup>887</sup> Id.; Ex. AG-31.

<sup>888</sup> Id.

<sup>889</sup> Id.

<sup>890</sup> 4 Tr 1512; Ex. AG-23.

<sup>891</sup> Id.

<sup>892</sup> Id.

<sup>893</sup> Id.

## **ABATE**

Mr. Walters recommends that the Commission adopt his recommended ROE of 9.45%.<sup>894</sup>

Mr. Walters states that authorized ROEs for regulated utilities have generally declined over the last 10 years, and have been below 10.0% for about the last nine years.<sup>895</sup> He adds that the distribution of authorized returns annually since 2016 shows that the majority of authorized ROEs since 2016 have generally been below 9.7%, with many of those being below 9.5%.<sup>896</sup>

Mr. Walters states that the credit ratings of the industry have improved since 2009, as in 2009, approximately 75% of natural gas utilities were rated BBB+ or higher, while currently, 85% of the industry has a rating of BBB+ or higher.<sup>897</sup>

Mr. Walters states that utilities have been able to access external capital to support capital expenditure programs.<sup>898</sup> He adds that capital expenditures for the regulated electric and natural gas delivery utilities have increased considerably over the period 2023 into 2024, and the forecasted capital expenditures remain elevated through the end of 2025.<sup>899</sup> He states that the outlooks for electric and natural gas industries reasonably align with capital expenditure outlooks for water utilities as noted by Regulatory Research Associates (RRA).<sup>900</sup> He adds that capital investments for the utility industry continue to stay at elevated levels, and these capital expenditures are expected to fuel utilities' profit

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<sup>894</sup> 4 Tr 1337.

<sup>895</sup> 4 Tr 1337-1338, Figure CCW-1.

<sup>896</sup> 4 Tr 1338-1339, Table CCW-1.

<sup>897</sup> 4 Tr 1340-1341, Table CCW-3.

<sup>898</sup> 4 Tr 1341.

<sup>899</sup> 4 Tr 1342, Figure CCW-2.

<sup>900</sup> 4 Tr 1341-1342, quoting RRA November 8, 2023, Utility Capital Expenditures report, RRA Financial Focus, a division of S&P Global Market Intelligence.

growth into the foreseeable future.<sup>901</sup> He asserts that this is clear evidence that the capital investments are enhancing shareholder value and are attracting both equity and debt capital to the utility industry in a manner that allows for funding these elevated capital investments.<sup>902</sup> He adds that while capital markets embrace these profit-driven capital investments, regulatory commissions also must be careful to maintain reasonable prices and tariff terms and conditions to protect customers' need for reliable utility service at reasonable rates, so as to avoid utility rates expanding beyond the ability of customers to pay, resulting in revenue constraints for utilities, which will impact their financial integrity.<sup>903</sup>

Mr. Walters states that there are robust valuations of regulated utility equity securities, which are an indication that utilities can sell securities at high prices, which is a strong signal that they can access equity capital under reasonable terms and conditions, and at relatively low cost.<sup>904</sup>

Mr. Walters concludes that generally, authorized ROEs, 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, and thus it is critical that this Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity.<sup>905</sup>

Mr. Walters states that the Federal Open Market Committee's (FOMC) actions are reflected in the market's valuation of both debt and equity securities.<sup>906</sup> He adds that the

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<sup>901</sup> 4 Tr 1342-1343, Figure CCW-2.

<sup>902</sup> 4 Tr 1343.

<sup>903</sup> Id.

<sup>904</sup> Id.; Ex. AB-4.

<sup>905</sup> 4 Tr 1344.

<sup>906</sup> 4 Tr 1344-1345, Figure CCW-3.

rise in the Federal Funds Rate has far outpaced the rise in Utility and Treasury yields while the spread of Utility bonds over Treasury bond yields have stabilized recently.<sup>907</sup> He states that the FOMC has recently shown signs of success in, and remains committed to, stabilizing consumer prices and promoting maximum employment through its monetary policy tools.<sup>908</sup>

Mr. Walters states that independent economists, surveyed by Blue Chip Financial Forecasts, expect current capital costs to increase at mixed rates over the near term, while maintaining levels that are still low by historical standards.<sup>909</sup> He adds that independent projections show that the consensus is the federal funds rate will increase at a rate much faster than that of long-term interest rates as measured by the 30-year Treasury bond, and that inflation, as measured through the Gross Domestic Product (“GDP”) price index, is expected to cool off in the near to intermediate term.<sup>910</sup> He states that the outlook for long-term interest rates in the intermediate to long term are also impacted by the current Fed actions and the expectation that eventually the Fed’s monetary actions will return to more-normal levels.<sup>911</sup>

Mr. Walters states that the outlook for increases in interest rates has jumped more recently relative to 2020 and part of 2021, but is still relatively modest compared to time periods prior to the beginning of the worldwide pandemic.<sup>912</sup> He adds that relatively low capital market costs are expected to prevail at least in the near-term and out over the next

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<sup>907</sup> 4 Tr 1345, Figure CCW-3.

<sup>908</sup> 4 Tr 1345-1346. Citations omitted.

<sup>909</sup> 4 Tr 1347.

<sup>910</sup> 4 Tr 1347-1348, Table CCW-4.

<sup>911</sup> 4 Tr 1348-1349, Table CCW-5.

<sup>912</sup> 4 Tr 1349-1350, Table CCW-5.

five to ten years.<sup>913</sup> While there is potential for some upward movement in the cost of capital, that upward movement is uncertain, noting that increases in the federal funds rate do not necessarily translate into increases in longer-term yields.<sup>914</sup>

Mr. Walters states that all credit rating agencies, including Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's"), see rate affordability as an important consideration in assessing utility credit.<sup>915</sup> He notes that in 2024, S&P updated its industry outlook to "Negative", noting that the credit quality of the industry has changed to BBB+ from an A- rating over the last few years.<sup>916</sup>

Mr. Walters states that credit rating agencies have been emphasizing rate affordability, maintaining adequate financial coverages of debt obligations, and supporting utilities' overall investment grade bond ratings.<sup>917</sup> He notes that in a recent industry report, Moody's explained that the regulated utilities' outlook remains "Negative" largely due to increased pricing pressures on customers.<sup>918</sup> He adds that in a report published in January of 2024, S&P specifically mentioned commodity price volatility, in combination with significant increases in capital investments, driving utility rate increases which may strain affordability concerns.<sup>919</sup> He states that Fitch opined that the regulated utilities' outlook is deteriorating due to elevated capital expenditures that put pressure on credit metrics with Fitch also noting the bill affordability concerns for ratepayers, and

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<sup>913</sup> Id.

<sup>914</sup> 4 Tr 1350, 1345, Figure CCW-3.

<sup>915</sup> 4 Tr 1351.

<sup>916</sup> 4 Tr 1350-1351, citing S&P Global Ratings: "Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens," February 14, 2024.

<sup>917</sup> 4 Tr 1351.

<sup>918</sup> 4 Tr 1352, citing Moody's Investors Service Outlook: "Regulated Electric and Gas Utilities – US 2023 outlook negative due to higher natural gas prices, inflation and rising interest rates," November 10, 2022.

<sup>919</sup> Id., citing S&P Global Ratings: "Industry Credit Outlook 2024: North America Regulated Utilities," January 9, 2024.

regulators' ability to balance the rate requests with increasing customer bills.<sup>920</sup> He concludes that as outlined by Moody's, S&P and Fitch, credit analysts are focusing on rate affordability as an important factor needed to support strong credit standing, as customers must be able to afford to pay their utility bills in order for utilities to maintain their financial integrity and strong investment grade credit standing.<sup>921</sup>

Mr. Walters states that in 2023, the utility sector underperformed the S&P 500 and has continued to do so in 2024.<sup>922</sup> He adds that it should be noted that the performance of the S&P 500 has largely been driven by a handful of "mega cap" companies because the S&P 500 is a market capitalization weighted index (meaning the higher the market capitalization a company has, the more influence it has on the index's performance).<sup>923</sup> He states that notwithstanding its recent underperformance relative to the S&P 500, the utility industry has been able to deliver generally positive and relatively stable returns during a period of elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world.<sup>924</sup>

Mr. Walters states that determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: *Bluefield Water Works v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas*, 320 U.S. 591 (1944).<sup>925</sup> He adds that as such, a fair return is based on the expectation that the utility costs reflect efficient and economical management, and

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<sup>920</sup> 4 Tr 1352-1353, citing FitchRatings. "North American Utilities, Power & Gas Outlook 2024," December 6, 2023.

<sup>921</sup> 4 Tr 1353.

<sup>922</sup> 4 Tr 1353, Figure CCW-4.

<sup>923</sup> 4 Tr 1353-1354, Citation omitted.

<sup>924</sup> 4 Tr 1354.

<sup>925</sup> 4 Tr 1355-1356.

the return will support its credit standing and access to capital, but the return will not be in excess of this level.<sup>926</sup> He states that utility rates that are consistent with these standards will be just and reasonable, and compensation to the utility will be fair and support financial integrity and credit-standing, under economic management of the utility.<sup>927</sup>

Mr. Walters states that the market's assessment of a company's investment risk is generally described by credit rating analysts' reports.<sup>928</sup> He adds that DTE's current credit ratings are A- and A3 from S&P and Moody's, respectively, and that DTE currently has a "stable" outlook from S&P and Moody's.<sup>929</sup> Mr. Walters notes that in its September 2023 report covering DTE, S&P stated in part as follows:

#### Business Risk

Our assessment of DTEG's business risk profile primarily reflects its very low-risk, regulated gas utility operations, very large customer base, and effective regulatory risk management. DTEG's utility operations provide indispensable services that are strategically important to economies, feature material barriers to entry, and essentially operate as a monopoly insulated from market challenges. The company benefits from the strength of the regulatory support in Michigan by managing its costs, filing forward-looking rate cases, and using various riders that enhance its cash flow predictability.<sup>930</sup>

Mr. Walters states in the same September 2023 report, S&P includes a chart which indicates that DTE has, on balance, over-earned its allowed ROE over the last several years.<sup>931</sup> He adds that this is consistent with DTE's historical test year figures showing

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<sup>926</sup> 4 Tr 1356.

<sup>927</sup> Id.

<sup>928</sup> 4 Tr 1357.

<sup>929</sup> Id., citing S&P Capital IQ, accessed on April 5, 2024.

<sup>930</sup> Id., citing S&P Global Ratings, RatingsDirect, DTE Gas Co., September 25, 2023.

<sup>931</sup> 4 Tr 1358.

that it has over-earned its allowed rate of return by a figure of approximately \$35.7 million on a revenue requirement basis.<sup>932</sup>

Noting that to be consistent with the *Hope* and *Bluefield* standards the allowed return should be commensurate with returns on investments in other firms of comparable risk, Mr. Walters asserts that a proxy group of similarly situated companies of comparable risk is needed to assess DTE's ROE proposal under this standard.<sup>933</sup> He states that he relied on the same proxy group developed by Dr. Villadsen, with six exceptions. He adds that he removed Chesapeake Utilities for not being a rated entity by S&P or Moody's, noting that credit ratings are a critical, independent assessment of total risk, and one of the most cited screening criteria used by rate of return analysts around the country.<sup>934</sup> He adds that he removed NiSource Inc. and Southwest Gas Holdings for being parties to significant merger and acquisition ("M&A") activities.<sup>935</sup> Finally, he removed Artesian Resources Corp., Global Water Resources, and York Water Company from the proxy group as they are not listed entities of the Water Utility Industry in the Value Line Investment Survey.<sup>936</sup>

Mr. Walters states that the Gas group has average ratings of A and A3 from S&P and Moody's, respectively, with the Gas group's rating of A from S&P being one notch higher than DTE's, while the Gas group's rating of A3 from Moody's is identical to the rating assigned to DTE.<sup>937</sup>

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<sup>932</sup> 4 Tr 1358-1359, citing Ex. A-1, Sch. A1.

<sup>933</sup> 4 Tr 1361.

<sup>934</sup> 4 Tr 1362.

<sup>935</sup> Id.

<sup>936</sup> 4 Tr 1363.

<sup>937</sup> Id.; Ex. AB-5.

Regarding his DCF model, Mr. Walters states that he relied on 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 5, 2024, and he used each proxy company's most recently paid quarterly dividend as reported in Value Line.<sup>938</sup> Noting that securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data, he relied on professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations from three sources: Zacks, S&P Capital IQ Market Intelligence ("MI"), and Yahoo! Finance.<sup>939</sup> He states that the average growth rate for my proxy group is 6.27% and a median growth rate of 6.43%.<sup>940</sup>

Mr. Walters states that the average constant growth DCF model returns for the gas group is 10.06%.<sup>941</sup> He adds that the constant growth DCF analysis for my proxy group is based on a group average long-term growth rate of 6.27%, which he does not consider such 6.27% growth rate to be a realistic forward-looking projection as the consensus of research on the subject finds a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity.<sup>942</sup> He states that the long-term maximum sustainable growth rate for a utility investment is limited by the projected long-term GDP growth rate, as that reflects the projected long-term growth rate of the economy as a whole, and notes that Blue Chip Financial Forecasts projects that over the next 5 and 10 years, the U.S. nominal GDP will grow at an annual rate of approximately

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<sup>938</sup> 4 Tr 1365.

<sup>939</sup> 4 Tr 1366.

<sup>940</sup> Id.; Ex. AB-6.

<sup>941</sup> 4 Tr 1367; Ex. AB-7.

<sup>942</sup> Id.

4.14%.<sup>943</sup> As such, he concludes that the average nominal growth rate over the next 10 years is around 4.14%, which he believes is a reasonable proxy of long-term growth.<sup>944</sup>

Regarding his sustainable growth DCF, Mr. Walters states that the sustainable growth rate is determined by the proportion of the utility's earnings that is retained and reinvested in its plant and equipment.<sup>945</sup> He asserts that the average sustainable growth rates for the gas proxy group using this internal growth rate model is 5.09%.<sup>946</sup> He states that a sustainable growth DCF analysis produces a gas proxy group average of 9.59%.<sup>947</sup>

Regarding his multi-stage growth DCF model, Mr. Walters states he conducted a multi-stage DCF analysis that reflects growth rate change over time. He asserts that the multi-stage DCF model reflects 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 11 and extending into perpetuity.<sup>948</sup> He adds that for the short-term growth period, he relied on the consensus of analysts' growth projections described above in relationship to his constant growth DCF model, for the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate, and for the long-term growth period, he assumed each company's growth would converge to the maximum sustainable long-term growth rate, while noting that because utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services, the U.S. GDP nominal growth

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<sup>943</sup> 4 Tr 1367-1368, citing Blue Chip Economic Indicators, March 11, 2024.

<sup>944</sup> 4 Tr 1368.

<sup>945</sup> Id.

<sup>946</sup> 4 Tr 1369; Ex. AB-9.

<sup>947</sup> Id.; Ex. AB-10.

<sup>948</sup> 4 Tr 1370-1371.

rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.<sup>949</sup> He states that the consensus of projected GDP growth is about 4.14% over the next 10 years.<sup>950</sup> He concludes that the average multi-stage DCF ROE for his gas proxy group is 8.97%.<sup>951</sup>

Mr. Walters states that because the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 6.27%, which is approximately 54% higher than the long-term projected GDP growth rate of 4.14% and thus is an unsustainable assumption which likely leads to an overstatement in the cost of equity for a low-risk regulated utility, he asserts that more weight should be given to the sustainable growth and multi stage models of the DCF.<sup>952</sup>

Regarding his risk premium model, Mr. Walters states his risk premium model is based on 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.<sup>953</sup> He adds that the five-year rolling average risk premium over Treasury bonds ranged from 4.17% to 7.17%, while the ten-year rolling average risk premium ranged from 4.30% to 6.92%.<sup>954</sup> He states that the five-year and ten-year rolling average risk premiums over contemporary "A" rated Moody's utility bond yields ranged from 2.80% to 5.97% and 3.11% to 5.75%,

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<sup>949</sup> 4 Tr 1371.

<sup>950</sup> 4 Tr 1373, citing Blue Chip Economic Indicators, March 11, 2024.

<sup>951</sup> 4 Tr 1375; Ex. AB-11.

<sup>952</sup> 4 Tr 1375-1376, Table CCW-8.

<sup>953</sup> 4 Tr 1376-1377; ex. AB-12.

<sup>954</sup> 4 Tr 1378; ex. AB-13.

respectively.<sup>955</sup> He states that the equity risk premium should reflect the market's perception of risk in the utility industry today, thus using the yield-spread between utility bonds and Treasury bonds since 1980.<sup>956</sup> He adds that he gave primary consideration to the Risk Premium results using Treasury bond and A-rated utility bonds, while also taking the results of adding the Baa-rated utility bond yield to the equity risk premium over A-rated utility bonds into consideration.<sup>957</sup> His results are summarized as follows:

Projected Treasury yield 9.64%, 13-week A-rated utility bond 9.81%, 13-week Baa-rated utility bond 10.04%, 26-week A-rated utility bond 9.96%, and 26-week Baa utility bond 10.21%.<sup>958</sup>

Regarding his CAPM model, Mr. Walters states that the CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.<sup>959</sup> He adds that because the cost of equity is a forward looking exercise, he used Blue Chip Financial Forecasts' projected 30-year Treasury bond yield of 4.00% for his CAPM analysis.<sup>960</sup> He states that the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.<sup>961</sup>

Mr. Walters states that market risk premium estimates are derived using two general approaches: a risk premium approach and a DCF approach.<sup>962</sup> He adds that using the normalized market risk premium of 5.50% with the normalized risk-free rate of

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<sup>955</sup> Id.; Ex. AB-14.

<sup>956</sup> 4 Tr 1378-1379; Ex. AB-15.

<sup>957</sup> 4 Tr 1379.

<sup>958</sup> 4 Tr 1380, Table CCW-9.

<sup>959</sup> 4 Tr 1381.

<sup>960</sup> 4 Tr 1382.

<sup>961</sup> Id.

<sup>962</sup> 4 Tr 1384.

4.47% as recommended by Kroll, results in a current expected, or forward-looking, market risk premium is 5.50%, implying an expected return on the market of 9.97%.<sup>963</sup> He states that the forward-looking risk premium-based estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate.<sup>964</sup> He concludes that the market risk premium then is the difference between the 11.40% expected market return and the projected risk-free rate of 4.00%, or 7.40%.<sup>965</sup>

Mr. Walters states that he employed two versions of the constant growth DCF model to develop estimates of the market risk premium. The first is the Federal Energy Regulatory Commission's ("FERC") method in its Opinion No. 569-A to perform a constant growth DCF analysis on each of the dividend-paying companies of the S&P 500 index.<sup>966</sup> He adds that the market risk premium then is the expected market return of 11.99%, less the projected risk-free rate of 4.00%, or 8.00%.<sup>967</sup> He states that the second DCF-based market risk premium estimate was derived by performing the same DCF analysis described above, except he used all companies in the S&P 500 index rather than just the dividend-paying companies.<sup>968</sup> He adds that the market risk premium then is the expected market return of 11.98% less the projected risk-free rate of 4.00%, or 8.00%.<sup>969</sup> He concludes that the average expected market return based on the DCF model is 11.99% and the average market risk premium based on the two DCF estimates is

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<sup>963</sup> Id. Citations omitted.

<sup>964</sup> 4 Tr 1385.

<sup>965</sup> Id.

<sup>966</sup> Id.

<sup>967</sup> 4 Tr 1386.

<sup>968</sup> Id.

<sup>969</sup> Id.

8.00%.<sup>970</sup> He notes that his average expected market return of 11.12% exceeds long-term market expectations of several financial institutions.<sup>971</sup> Mr. Walters CAPM results averages range from 9.34% to 10.11%.<sup>972</sup>

Mr. Walters states that based on his analyses of the various methodologies, he estimates DTE's current market cost of equity to be in the reasonable range of 9.10% to 9.80%.<sup>973</sup> He adds that his recommended range accounts for the unsustainable growth rates assumed in the constant growth DCF model and the irrational assumption that Value Line's current beta estimates are reflective of current investor expectations.<sup>974</sup> He concludes that based on his assessment of DTE's overall risk profile and the results of these analytical methods, he recommends that this Commission authorize DTE an ROE of 9.45%.<sup>975</sup>

Mr. Walters disagrees with Dr. Villadsen's ROE recommendation. He states that Dr. Villadsen's recommended ROE of 10.0% for DTE is excessive and unreasonable for a low-risk regulated utility company.<sup>976</sup>

Mr. Walters states that the model ROE results of Dr. Villadsen's studies applied to her proxy Full Sample indicate that the required ROE is in the range of 8.3% to 10.6%, and that she then increases her market ROE estimate by adjusting her results upward in the range of 0.2%-1.7% using an overall cost of capital ("OCC") methodology.<sup>977</sup> He adds that the OCC method employed by Dr. Villadsen is identical to the After-Tax Weighted

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<sup>970</sup> Id.

<sup>971</sup> 4 Tr 1386-1387, Table CCW-9.

<sup>972</sup> 4 Tr 1390, Table CCW-11.

<sup>973</sup> 4 Tr 1391, Figure CCW-5.

<sup>974</sup> Id.

<sup>975</sup> Id.

<sup>976</sup> 4 Tr 1392.

<sup>977</sup> 4 Tr 1393.

Average Cost of Capital (“ATWACC”) methodology previously rejected by regulatory commissions throughout the country, and that this ATWACC adjustment increases her recommended range up to 10.0%-10.7%.<sup>978</sup>

Mr. Walters states that the ATWACC methodology is poor regulatory policy and should be rejected.<sup>979</sup> He adds that the ATWACC introduces significant additional instability and unreliability into the utility’s cost of service and tariff rates, and that the ATWACC artificially increases rates to produce an excessive ROE opportunity for utility investors, as if the utility were an unregulated affiliate.<sup>980</sup> He states that the Commission has rejected the application of the ATWACC methodology in Case Nos. U-18014 and U-18255.<sup>981</sup>

Regarding Dr. Villadsen’s DCF analysis, Mr. Walters states that she applies her ATWACC adjustment and increases her constant growth DCF result from 10.4% to 11.9%, and her multi-stage DCF result from 8.7% to 8.9%.<sup>982</sup> He adds that her recommendation places too much weight on the results of her constant growth DCF analysis and not nearly enough weight on her multi-stage DCF results, as her average growth rate projection rate, which greatly exceeds her projected growth rate of 3.9% for the US economy by approximately 85%, is unsustainable and defies economic logic.<sup>983</sup> He also states that Dr. Villadsen uses several results from her DCF analyses – albeit only removing what she determined to be low-end outliers and not high-end outliers --

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<sup>978</sup> 4 Tr 1394.

<sup>979</sup> 4 Tr 1395.

<sup>980</sup> 4 Tr 1396.

<sup>981</sup> 4 Tr 1396-1397, citing Case No. U-18014, Order, January 31, 2017, page 66 and Case No. U-18255, Order, April 18, 2018, page 32.

<sup>982</sup> 4 Tr 1398, citing Ex. A-14, Sch. D5.6-5.8.

<sup>983</sup> Id.

ultimately causing a significant upward bias to her results.<sup>984</sup> He adds that because Dr. Villadsen's DCF analyses include results as high as 16.0% and as low as 4.4%, a more reasonable estimate for the DCF analysis would be based on the medians of her unadjusted results of 7.2% (multi-stage DCF) and 9.7% (constant growth DCF).<sup>985</sup>

Regarding Dr. Villadsen's CAPM analysis, Mr. Walters states that applying her market risk premium inputs with her Value Line betas, she produces two bare-bones CAPM estimates of 9.9% and 8.7% for her Full Sample.<sup>986</sup> He adds that Dr. Villadsen proposes two separate adjustments to the model results in an attempt to capture the difference in financial risk.<sup>987</sup> He states that first, she proposes to add to her base CAPM return estimate an ATWACC ROE adjustment, which produces an ATWACC-adjusted CAPM return for her Full Sample in the range of 10.0% to 11.5%.<sup>988</sup> He adds that second, Dr. Villadsen proposes a financial risk adjustment to reflect a leveraged beta adjustment, which adds approximately 40 to 60 basis points to the base CAPM return estimates.<sup>989</sup> He asserts that this leverage adjustment to the base CAPM return estimate produces an excessive and unreasonable ROE for DTE.<sup>990</sup>

Mr. Walters also disagrees with Dr. Villadsen's use of the Value Line beta estimates, asserting that these beta estimates are abnormally high and are unlikely to be sustained over the long-term, and as such, asserts it to be reasonable to consider the historical average of the proxy group's Value Line betas.<sup>991</sup> He adds that assuming her

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<sup>984</sup> 4 Tr 1398-1399.

<sup>985</sup> 4 Tr 1399.

<sup>986</sup> Id.

<sup>987</sup> Id.

<sup>988</sup> Id.

<sup>989</sup> Id.

<sup>990</sup> Id.

<sup>991</sup> 4 Tr 1400.

risk-free rate of 3.95% and market risk premiums of 5.72% and 7.17%, and incorporating the historical average Value Line beta of 0.75 would produce CAPM results of 8.2% and 9.3% respectively.<sup>992</sup>

In addition, Mr. Walters states that as an alternative to her ATWACC adjustment to her CAPM results, Dr. Villadsen measures an additional ROE adjustment based on leveraged adjustments to the beta component of the CAPM study by applying the Hamada method to de-lever and re-lever the beta component in both the CAPM and the ECAPM, which increases the Full Sample Value Line beta from 0.83 to 1.06 (without taxes) and 1.01 (with taxes) for the Full Sample.<sup>993</sup> He adds that the Hamada model produces CAPM results in the range of 9.7% to 11.5% and ECAPM results in the range of 9.7% to 11.5% for the Full Sample.<sup>994</sup> He argues that Dr. Villadsen's financial leverage adjustments are generally not accepted in establishing a fair ROE in regulated rate-setting proceedings.<sup>995</sup>

Regarding Dr. Villadsen's ECAPM return estimates, Mr. Walters states she included an adjusted beta within her ECAPM studies, which double counts the purpose of the ECAPM study.<sup>996</sup> He adds that the use of an adjusted beta such as those published by Value Line produces comparable adjustments to the CAPM return estimate.<sup>997</sup> He asserts that there is simply 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.<sup>998</sup>

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<sup>992</sup> Id.

<sup>993</sup> 4 Tr 1400-1401.

<sup>994</sup> 4 Tr 1401.

<sup>995</sup> Id.

<sup>996</sup> Id.

<sup>997</sup> 4 Tr 1402.

<sup>998</sup> 4 Tr 1403.

Regarding Dr. Villadsen's Risk Premium analysis, Mr. Walters states Dr. Villadsen's regression-derived risk premium estimates of 6.26% for gas utilities is significantly higher than the equity risk premiums realized in 2023, which produces an excessive risk premium estimate and overstates the cost of equity.<sup>999</sup> He adds that a widening equity risk premium is contrary to what is expected to occur in 2024, as the equity risk premium is expected to narrow in 2024 relative to 2023 for several reasons as "regulators navigate the ongoing energy transition and potential affordability challenges posed by higher interest rates and rising costs."<sup>1000</sup>

### **Citizens Utility Board of Michigan (CUB)**

Mr. Bandyk states estimating the cost of equity for a regulated utility must be done carefully so as to arrive at a return that is "just and reasonable," pursuant to the legal standards governing public utility regulation set forth in the United States Supreme Court cases *Bluefield Water Works v. Public Service Commission of West Virginia* and *Federal Power Commission v. Hope Natural Gas Co.*<sup>1001</sup> Noting that the Court in *Hope* made clear that the determination of what return is "sufficient" in that regard must also involve a consideration of the interests of the company's customers, Mr. Bandyk argues that, just as a return for a utility that is set below the amount "commensurate with returns on investments in other enterprises having corresponding risks" causes the utility to lose wealth relative to what it should earn with a more appropriate return, a return that is set above this amount will cause the utility's customers to be overcharged and lose wealth

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<sup>999</sup> 4 Tr 1404.

<sup>1000</sup> 4 Tr 1405, citing S&P Capital IQ, RRA Regulatory Focus, Average authorized energy ROEs rise in 2023 amid record rate case activity, January 25, 2024.

<sup>1001</sup> 4 Tr 950-951.

relative to what they would be charged with a lower and more appropriate return.<sup>1002</sup> He adds that in this latter case, that wealth is instead transferred from customers to the utility holding company's shareholders.<sup>1003</sup> He states that in *Hope*, the Supreme Court held that for a public utility commission's determination of "just and reasonable" rates, it is the result reached, not the method employed, which is controlling, and that result should be a rate that people would reasonably consider to be commensurate with the risk of the investment.<sup>1004</sup>

Mr. Bandyk states that there is strong evidence from multiple observers that public regulatory commissions on average have tended to set electric utility ROEs above what objective observers in the financial community would arrive at using the widely accepted methods for estimating ROE.<sup>1005</sup> He asserts that the failure by commissions to match a market-based ROE has resulted in a transfer of wealth from ratepayers to shareholders.<sup>1006</sup>

Mr. Bandyk states that arriving at an ROE is a process of estimation, and that process will invariably include some degree of subjectivity, asserting that subjective factors can influence any human decision-making process, including the decisions of public regulatory commissions, and lead to results that vary from objective methods.<sup>1007</sup>

Mr. Bandyk references prior testimony in Case No. U-20836 which compares the average ROE for U.S. stocks as a whole since 1990 to the ROEs for regulated electric and gas utilities awarded by public regulatory commissions over the same time period,

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<sup>1002</sup> 4 Tr 951.

<sup>1003</sup> *Id.*

<sup>1004</sup> *Id.*

<sup>1005</sup> 4 Tr 952.

<sup>1006</sup> *Id.*

<sup>1007</sup> *Id.*

including Figure 2 which shows that the average awarded ROEs have been consistently above the market-based ROEs by about two percentage points in almost every year for over three decades.<sup>1008</sup> He adds that there is published evidence indicating that regulators tend to set ROEs above what the market would bear.<sup>1009</sup> The article states

There is mounting evidence that investment in utility stocks has outperformed the broader market in the past, and will continue to do so. . . Regulated utilities are less risky than competitive industries, and therefore are supposed to produce a lower total return over time.<sup>1010</sup>

The article also states that a) Jack Bogle, the founder of Vanguard Group, provides rigorous analysis that the long-term total return for the broader market will be around 7% going forward, b) Professor Burton Malkiel, corroborates that 7% in the latest edition of *A Random Walk Down Wall Street*, and c) Institutions like pension funds are piling on risky investments to try and get to a 7.5% total return, as reported by the Wall Street Journal (December 24, 2015).<sup>1011</sup>

Mr. Bandyk states:

A higher return implies higher risk, so the empirical result that awarded ROEs are higher than market returns would imply that regulated utilities are riskier investments than the market as a whole. But they are indeed not riskier. Consider the noncontroversial fact that regulated utility returns tend to be less risky than the market as a whole. This phenomenon can be observed simply by looking at the betas of regulated utility holding companies. Beta is a measurement of the sensitivity of a stock's returns relative to those of the market as a whole. Utility holding company betas tend to be less than one, meaning that those stocks are less sensitive to changes in overall market returns.<sup>1012</sup>

Mr. Bandyk adds that regulated utilities historically have been awarded ROE's above market returns because public regulatory commissions have tended to accept

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<sup>1008</sup> 4 Tr 953, Figure 2, *citing* Case No. U-20836-0479, Direct Testimony of David J. Garrett, 8 TR 3880.

<sup>1009</sup> 4 Tr 953-954; Ex. CUB-6.

<sup>1010</sup> Ex, CUB-5, p. 1.

<sup>1011</sup> Ex. CUB-5, p. 2. Citations omitted.

<sup>1012</sup> 4 Tr 954-955.

estimates for ROE that are above fair, market-based ROE estimates.<sup>1013</sup> Noting Mr. Villadsen's testimony that "the allowed return on equity needs to be at least as high as the expected return offered by alternative investments of equivalent risk or investors will choose these alternatives instead", Mr. Bandyk asserts that "the allowed return on equity should also be *no higher* than the expected return offered by alternative investments of equivalent risk or ratepayers will be essentially taxed to provide an excess return to investors."<sup>1014</sup>

Mr. Bandyk asserts that Dr. Villadsen's recommended ROE of 10.25% is not a just and reasonable return.<sup>1015</sup> He adds that Dr. Villadsen's recommended ROE is inflated above what would be a fair return due to several overestimated inputs into her DCF and CAPM analysis as well as her use of a Risk Premium model that essentially recycles the overestimations of ROE by other regulatory commissions.<sup>1016</sup> He states that DTE Gas customers would pay for an excessive return if the Commission approves DTE's recommended ROE in this case.<sup>1017</sup> He asserts:

If the MPSC were to accept the utility's request for a rate increase without changes, DTE would collect about \$419.2 million from customers for a return on its rate base, based on an overall rate of return of 6.04% and a total jurisdictional electric rate base of \$6.94 billion. If the ROE were instead the market-based ROE of 9.46% that I am recommending in this case, that return would fall from \$419.2 million to \$396.3 million, resulting in savings to customers of \$22.9 million on an annualized basis.<sup>1018</sup>

Mr. Bandyk states that his ROE estimate is based on the Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow (DCF) methods, which he asserts are

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<sup>1013</sup> 4 Tr 955.

<sup>1014</sup> Id. Emphasis in original.

<sup>1015</sup> 4 Tr 956.

<sup>1016</sup> Id.

<sup>1017</sup> 4 Tr 956.

<sup>1018</sup> Id. Citations omitted.

probably the two most widely accepted methods for calculating ROE.<sup>1019</sup> Mr. Bandyk adds that the result of his CAPM analysis is 9.14%, and that the result of his DCF analysis is 8.90%.<sup>1020</sup> Mr. Bandyk states that the average of my model results suggests that an ROE lower than 9.46% would be a market-based cost of equity for DTE Gas, but asserts that DTE Gas is not a competitive business solely answerable to market forces, which helps explain why its awarded ROE has historically been significantly higher than the market-based cost of equity. He nonetheless recommends that that an ROE lower than 9.46% would be a market-based cost of equity for DTE Gas, which 9.46% is the midpoint between the average result of his models (9.10%) and the 9.90% ROE awarded to DTE Gas in its last rate case (U-20940), reasoning that any significant changes in DTE Gas's ROE should be implemented gradually so as not to create unnecessary instability in the company's market value.<sup>1021</sup>

Regarding Dr. Villadsen's use of the CAPM formula, Mr. Bandyk states that he has no objection to the risk-free rate she selected, and asserts that her use of the proxy group average beta as the basis for a beta that is unlevered and then relevered at DTE Gas's proposed capital structure is also sound.<sup>1022</sup> He adds, however, that Ms. Villadsen's CAPM estimate for ROE is inflated by her choice of the equity risk premium (ERP) for her Scenario 1 CAPM analysis, which 7.17% ERP is the historical average premium of market returns over the income returns on government bonds from 1926 to 2022.<sup>1023</sup> He states that historical estimates like this one have a flawed methodology that leads to an

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<sup>1019</sup> 4 Tr 957.

<sup>1020</sup> *Id.*

<sup>1021</sup> 4 Tr 957-958.

<sup>1022</sup> 4 Tr 958.

<sup>1023</sup> 4 Tr 959.

inaccurate estimate of market return, asserting that the historical estimate for ERP is extremely sensitive to the historical time period selected, and that historical estimates of ERP are subject to the problem of survivorship bias -- where returns that go into historical ERPs tend to be those from stocks that remain in the market, rather than those that drop out – which tends to inflate historical ERPs.<sup>1024</sup>

As an alternative, Mr. Bandyk states that the ERP he used in his estimate is an average of the implied equity risk premium estimate from three sources: Dr. Damodaran - 4.23%, 2023 IESE Business School survey - 5.7%, and Kroll for 2023 – 5.5%.<sup>1025</sup> He notes that the value of these ERP estimates is very close to the 5.72% value that Ms. Villadsen uses in her Scenario 2 CAPM analysis, and asserts that all come from widely-used, highly reputable sources that lack the methodological problems that come with extrapolating a forward ERP from historic data such as Dr. Villadsen's 7.17% historic risk premium.<sup>1026</sup> He disputes that Dr. Villadsen's claim that her 7.17% risk premium is more reasonable because it is closer to the 7.92% and 7.99% risk premiums she calculates, arguing that those risk premiums are much higher than the risk premiums he used from that all come from widely-used, highly reputable sources.<sup>1027</sup>

Mr. Bandyk states that he did not use the ECAPM because Staff has historically rejected the ECAPM method as part of ROE analyses in rate cases.<sup>1028</sup>

Regarding the DCF analysis, Mr. Bandyk states that he endorses Ms. Villadsen's DCF analysis multi-stage approach with a perpetual growth rate of 3.9%, matching the

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<sup>1024</sup> 4 Tr 959-960.

<sup>1025</sup> 4 Tr 960; Ex. CUB-8. Citations omitted.

<sup>1026</sup> 4 Tr 961; Ex. CUB-8.

<sup>1027</sup> Id.; Ex. A-14, Sch. D5.17.

<sup>1028</sup> 4 Tr 962. Citation omitted.

forecasted long-term nominal U.S. GDP growth rate.<sup>1029</sup> He adds that Ms. Villadsen's simple DCF model lacks a long-term growth rate and relies only on a short-term growth rate, which leads to an unrealistic and meaningless outcome.<sup>1030</sup> He states that if the growth rate used in the DCF model is higher than that of the growth rate of the economy as a whole, that implies that in the long run, DTE would grow bigger than the entire U.S. economy, which outcome is theoretically impossible.<sup>1031</sup>

Mr. Bandyk states that the Risk Premium Model as used by Ms. Villadsen should be disregarded because it introduces into the calculation of ROE the reliance on ROEs set by other regulatory commissions, about which academic research has shown the reliance on historic allowed returns to be hopelessly distorted from what objective methods to determine a just and reasonable rate would find.<sup>1032</sup> He adds that another reason he did not use this method is because the result of its application is divergent from the results from methods that, as Ms. Villadsen puts it, are "underpinned by fundamental financial principles."<sup>1033</sup> He asserts that the status of this Model as less preferable to the CAPM or DCF methods is supported by Dr. Villadsen's application of the method to merely check the reasonableness of the ROE ranges produced by her other methods.<sup>1034</sup>

### **Soulardarity; We Want Green, Too; Urban Core Collective**

Mr. Koepfel states that, while he is not an economist, it is his general perspective that the utility industry is overcompensated.<sup>1035</sup> He notes that a 2023 study from the

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<sup>1029</sup> Id.

<sup>1030</sup> Id.

<sup>1031</sup> 4 Tr 963.

<sup>1032</sup> 4 Tr 964.

<sup>1033</sup> Id.

<sup>1034</sup> 4 Tr 965.

<sup>1035</sup> 4 Tr 1021.

Energy Institute at Haas found that utilities charged customers between \$2 billion and \$20 billion in excess costs each year by 2020 resulting from rates of return being higher than the utilities' cost of capital and those higher rates resulting in excess capital spending.<sup>1036</sup> He asserts that DTE Gas similarly is seeking a higher ROE than its cost of capital and those higher rates would result in excess capital spending by DTE.<sup>1037</sup>

Mr. Koepfel asserts that the more utilities spend on capital, the more profit they make, creating a "capital bias" to spend more at the expense of ratepayers, even when it is not prudent.<sup>1038</sup> He adds that in the case of DTE Gas, the proposed overcompensation poses the additional harm of exacerbating and extending the mid-transition.<sup>1039</sup> He notes that the 2023 study from the Energy Institute at Haas suggests that a one percentage point rise in the return on equity increases capital investment by 5%.<sup>1040</sup> He asserts that by overcompensating shareholders, the Commission would encourage continued investment into a legacy system which, from the standpoint of a just and equitable energy transition, must be systemically decommissioned.<sup>1041</sup>

Mr. Koepfel states that a lower ROE for gas utilities relative to electric utilities disincentivizes capital investment in gas infrastructure, investment that is incompatible with a decarbonized and electrified future in which there is no or only a highly limited role for gas.<sup>1042</sup> He adds that approving a lower ROE for gas utilities relative to electric encourages parent companies like DTE Energy to prioritize electrification and investment

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<sup>1036</sup> *Id.*, *citing* Ex. FLO-41, Karl Dunkle Werner & Stephen Jarvis, Energy Inst. at Haas, Rate of Return Regulation Revisited (Energy Inst. Working Paper No. 329R, Revised Aug. 2023), at 37.

<sup>1037</sup> *Id.*

<sup>1038</sup> *Id.*

<sup>1039</sup> 4 Tr 1021-1022.

<sup>1040</sup> 4 Tr 1022. Citation omitted.

<sup>1041</sup> *Id.*

<sup>1042</sup> *Id.*

in electric infrastructure.<sup>1043</sup> He states that public service commissions overcompensate utilities in general, such that the Commission should take a critical eye to ROEs universally, while recognizing the unique problems caused by incentivizing overinvestment in gas infrastructure.<sup>1044</sup> He adds that the Commission should reject the proposed increase in Return on Equity and consider reducing the ROE.<sup>1045</sup>

### **City of Ann Arbor**

Dr. Stults states that DTE is requesting an ROE of 10.25%, which is an increase of 35 points from the current authorized ROE of 9.90%, which was approved in Case No. U-20940.<sup>1046</sup> She notes that Fitch stated on March 21, 2024 that DTE's current authorized ROE of 9.90% "compares favorably with industry averages," and that the regulatory environment for natural gas utilities in Michigan is "constructive."<sup>1047</sup>

Dr. Stults states that Dr. Villadsen recommended an ROE of 10.25% in Case No. U-20940, in part because she found DTE to be "of higher than average risk."<sup>1048</sup> She adds that Commission authorized an ROE of 9.90%, reasoning in part that it "accomplishes the objectives of adequately compensating DTE Gas for its company specific business risk, ensuring the financial well-being of the utility, and maintaining a strong ability to attract capital."<sup>1049</sup> She adds that following the Commission's order, Fitch stated the authorized

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<sup>1043</sup> Id.

<sup>1044</sup> 4 Tr 1022-1023.

<sup>1045</sup> 4 Tr 1040.

<sup>1046</sup> 3 Tr 515.

<sup>1047</sup> Id., citing Ex. A2-14.

<sup>1048</sup> 3 Tr 516, citing Ex. AA-15.

<sup>1049</sup> Id., citing Case No. U-20940, Order, December 9, 2021, p. 90-91.

ROE of 9.90% “compares favorably with industry averages,” and that it views the Commission’s approval of a 9.90% ROE as “a credit constructive outcome.”<sup>1050</sup>

Dr. Stults argues that the Commission’s approval of authorized ROEs lower than Dr. Villadsen’s recommended ROEs in DTE’s past two general rate cases did not negatively impact Fitch’s Long-Term Issuer Default Rating of DTE.<sup>1051</sup> She adds that DTE made several statements to its investors regarding shareholder returns, risk of investment, and the regulatory environment in Michigan, as follows: in April 2024, DTE highlighted that one of the ways it is “Delivering premium shareholder returns,” is by “Increas[ing] 5-year utility capital investment by \$2 billion over previous plan,” in April 2023, DTE noted the company was able to deliver “premium shareholder returns,” while “maintaining solid investment-grade credit ratings” and “providing a healthy dividend,” in January 2022, DTE said it was “[d]elivering premium shareholder returns,” and “well-positioned for future growth,” and touted extending its 7% dividend growth to 2022 and that in September 2021, DTE said it “[a]ttracts shareholders desiring predictable, low-risk growth,” and is “Targeting dividend growth and payout ratio consistent with pure-play utility peers,” as well as noted it is “operating in a constructive regulatory environment.”<sup>1052</sup>

Dr. Stults states that as DTE has itself stated, DTE has been able to consistently deliver “premium” returns to shareholders and maintain a positive and stable credit rating, despite having an authorized ROE substantially lower than Dr. Villadsen claimed was necessary to continue attracting capital.<sup>1053</sup> She adds that Dr. Villadsen has a pattern of recommending an above-average ROE based on a claim that DTE is a higher-than-

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<sup>1050</sup> Id., citing Ex. AA-16.

<sup>1051</sup> Id., citing Ex. AA-14, AA-16, AA-18.

<sup>1052</sup> 3 Tr 517-518, citing Ex. AA-19, p. 3-4; Ex. AA-20, p. 4, 16; Ex. AA-21, p. 4-5; Ex. AA-22, p. 6-7.

<sup>1053</sup> 3 Tr 518-519.

average business risk, despite consistently being proven wrong by the review of rating agencies, DTE's long history of earning its authorized ROE, and its "deliver[y of] premium shareholder returns" even when an ROE significantly below her recommendation is authorized by the Commission.<sup>1054</sup> She asserts that this history is proof that an ROE lower than the one recommended by Dr. Villadsen would be sufficient to allow DTE to mitigate risk and provide an opportunity for reasonable shareholder returns.<sup>1055</sup>

### **Rebuttal**

In rebuttal, Dr. Villadsen states that Staff's and the Intervenors' recommendations are too low as they are below the currently authorized ROE for DTE Gas (9.90%) and economic / financial conditions indicate an increase in the cost of equity.<sup>1056</sup> She adds that the recommendations are based on flawed estimations of the cost of equity.<sup>1057</sup> She notes that even before correcting the flaws in their analyses, the upper end of Staff's and Messrs. Walters' and Coppola's range of ROE results averages is 10.58%, which is 33 basis points above his recommended ROE of 10.25%, and that Mr. Ufolla recommends a reasonable range for DTE Gas' ROE of 9.3% to 10.3%, which is inclusive of his recommended ROE of 10.25%.<sup>1058</sup> She asserts that given the increase in interest rates and increase in natural gas utilities exposure to de-carbonization initiatives, it is simply not reasonable to decrease neither the authorized ROE nor the equity percentage.<sup>1059</sup>

Dr. Villadsen states that Messrs. Ufolla, Walters, and Coppola each take issue with her use of the after-tax weighted average cost of capital and Hamada adjustment to

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<sup>1054</sup> 3 Tr 519.

<sup>1055</sup> Id.

<sup>1056</sup> 4 Tr 2544. Citation omitted.

<sup>1057</sup> Id.

<sup>1058</sup> 4 Tr 2544-2545. Citations omitted.

<sup>1059</sup> 4 Tr 2545.

account for differences in financial leverage between the proxy companies and DTE Gas.<sup>1060</sup> She adds that Messrs. Ufolla, Walters, and Coppola argue that financial risk adjustments lack regulatory precedent in Michigan and other US jurisdictions, and that Mr. Walters also incorrectly states that the Commission rejected the ATWACC methodology in Case No. U-18255.<sup>1061</sup> She asserts that Messrs. Ufolla, Walters, and Coppola disregard basic tenets of financial theory by failing to consider the impact of leverage on the cost of equity, thereby creating a downward bias in their cost of equity estimates.<sup>1062</sup> She argues that Mr. Walters's statement that the Commission rejected financial leverage adjustments in the final order in Case No. U-18255 and Mr. Ufolla's statement that the ATWACC "has never been approved by this Commission" are "not entirely true" as in the final order in Case No. U-18255, the Commission said that "little weight should be given to the utility's ATWACC calculations."<sup>1063</sup>

Dr. Villadsen states that if the Commission were to grant DTE Gas a lower equity capital structure, as recommended by Mr. Ufolla (51%) or Messrs. Walters and Coppola (50%), the allowed ROE must be increased to provide a fair, risk-adjusted return reflecting the higher level of financial leverage, as at these lower equity capital structures, the ROE estimates from her Gas Sample would increase by 3 to 21 bps.<sup>1064</sup>

Dr. Villadsen disputes the criticisms of her proxy group.<sup>1065</sup> She agrees with Mr. Coppola that UGI should be excluded as the majority of UGI's assets are dedicated to

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<sup>1060</sup> 4 Tr 2546. Citations omitted.

<sup>1061</sup> Id. Citations omitted.

<sup>1062</sup> 4 Tr 2548.

<sup>1063</sup> 4 Tr 2549. Citations omitted.

<sup>1064</sup> 4 Tr 2562-2563.

<sup>1065</sup> 4 Tr 2563.

non-rate regulated activities.<sup>1066</sup> She disagrees with Mr. Coppola's inclusion of Black Hills as it is classified as an electric utility by Value Line, and Mr. Coppola does not provide a rationale as to why he needed to add Black Hills to his natural gas sample.<sup>1067</sup> Regarding ABATE's criticism to including NiSource, she states that the two related transactions do not fail her M&A screen.<sup>1068</sup> Regarding ABATE's criticism to including Southwest Gas, she states that it is appropriate to include Southwest Gas Holdings in the natural gas proxy group but that Southwest Gas would now be excluded due to its spinoff of Centuri Holdings.<sup>1069</sup>

Dr. Villadsen states that she has serious concerns about the CAPM derived ROE estimates of Messrs. Ufolla, Walters, Coppola, nor Bandyk as none rely on the Hamada adjustment to account for differences in financial leverage and none rely on the ECAPM.<sup>1070</sup>

Regarding Staff's CAPM analysis, Dr. Villadsen notes Mr. Ufolla's his failure to consider the impact of financial leverage on the cost of equity and his reliance on too low of an MRP.<sup>1071</sup> She states that Mr. Ufolla's risk-free rate is too low based on current market conditions and is not reflective of the market's current expectations for interest rates when DTE Gas' rates will be in effect.<sup>1072</sup> Regarding ABATE's CAPM, Dr. Villadsen disagrees with Mr. Walters his reliance on historical betas, his reliance on Kroll's normalized MRP, and his failure to consider the impact of financial leverage on the cost

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<sup>1066</sup> 4 Tr 2564-2565.

<sup>1067</sup> 4 Tr 2565. Citation omitted.

<sup>1068</sup> 4 Tr 2566-2567.

<sup>1069</sup> 4 Tr 2567.

<sup>1070</sup> 4 Tr 2569.

<sup>1071</sup> 4 Tr 2569.

<sup>1072</sup> 4 Tr 2570.

of equity.<sup>1073</sup> She states that her primary concern with Mr. Coppola's CAPM estimate is his failure to recognize the impact of financial leverage on the cost of equity.<sup>1074</sup> Regarding CUB's CAPM estimate, she asserts that Mr. Bandyk's MRP estimate has numerous problems that downwardly bias his ROE estimates to below almost every CAPM estimate put forth by any witness in this proceeding, such that Mr. Bandyk's CAPM estimates should not be given any weight by the Commission.<sup>1075</sup>

Regarding the DCF model results, Dr. Villadsen states that there are shortcomings with Staff's and the Intervenor's models, while noting that Messrs. Ufolla's and Walter's results are supportive of her recommended ROE of 10.25% while disregarding the low-end of Mr. Walters' DCF range as an outlier and much too low.<sup>1076</sup> She states that the largest issue is Mr. Ufolla's failure to account for differences in financial leverage in his DCF analysis.<sup>1077</sup> As to Mr. Coppola's DCF model results, Dr. Villadsen asserts that Mr. Coppola relies on an annualized version of the DCF model that delays the estimated payment of dividends to investors, which underestimates the cost of equity; that Mr. Coppola's growth rates are lower than those of Messrs. Ufolla and Walters; and that Mr. Coppola's DCF model fails to account for differences in financial leverage.<sup>1078</sup> As to Mr. Walters DCF model results, she states that Mr. Walters introduces unnecessary volatility into his average stock price by taking the high and low price over a 13-week period, Mr. Walters' sustainable growth rate model only relies on one source for its growth rate—Value Line, and that his DCF models fail to account for differences in financial

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<sup>1073</sup> 4 Tr 2571. Citation omitted.

<sup>1074</sup> 4 Tr R 2572.

<sup>1075</sup> 4 Tr 2574.

<sup>1076</sup> 4 Tr 2575.

<sup>1077</sup> 4 Tr 2576.

<sup>1078</sup> 4 Tr 2577. Citation omitted.

leverage.<sup>1079</sup> She adds that her primary concern with Mr. Bandyk is that he does not consider the results from her single stage DCF model.<sup>1080</sup>

Regarding Staff's and Intervenors' Risk premium models, Dr. Villadsen states that Messrs. Ufolla's, Walters', and Coppola's risk premium models fail to take into account the inverse relationship between utilities' equity risk premium and the level of interest rates.<sup>1081</sup>

Dr. Villadsen states that Mr. Walters and Dr. Stults discuss commentary from credit rating agencies regarding business risk, levels of return, and utilities' ability to access capital, but asserts that, in doing so, they conflate the attraction of debt and equity capital – credit ratings measure credit risk, while equity investors are considering the return that is available on alternative investments of similar equity risk.<sup>1082</sup> She argues that the fact that DTE Electric has maintained its credit rating and is able to attract debt capital does not imply that the allowed ROE is commensurate with returns on investments in other enterprises having corresponding risks.<sup>1083</sup>

Noting that Messrs. Walters, Bandyk, and Dr. Stults put forth evidence that compares recently allowed ROEs and her recommendation, Dr. Villadsen states Mr. Walters' figures showed that allowed ROEs generally increased from 2006 until the financial crisis (2009), after which the allowed ROEs for utilities declined until about 2020, and since then the average allowed ROEs for utilities have increased.<sup>1084</sup>

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<sup>1079</sup> 4 Tr 2577-2578.

<sup>1080</sup> 4 Tr 2578.

<sup>1081</sup> 4 Tr 2580-2581. Citation omitted.

<sup>1082</sup> 4 Tr 2587. Citation omitted.

<sup>1083</sup> *Id.*

<sup>1084</sup> 4 Tr 2588-2589. Citations omitted.

Noting that Messrs. Ufolla, Walters, and Coppola argue that use of adjusted betas in the ECAPM methodology is not appropriate, that the use of adjusted betas “double counts” increase impact of the adjustment, that Mr. Coppola argues that the use of long-term risk-free rates makes the ECAPM unnecessary, and that Mr. Coppola argues that the ECAPM is not widely accepted in US regulatory settings, Dr. Villadsen states that the ECAPM has merit, that Commission should be presented with the best possible analysis regardless of whether the analysis is “widely used” by regulators, and that there is no double-counting in using adjusted betas in the ECAPM.<sup>1085</sup>

In rebuttal, Mr. Walters states that Mr. Ufolla’s proxy group includes several inappropriate companies, and that Mr. Ufolla fails to consider the results of a multi-stage DCF analysis.<sup>1086</sup> He asserts that without these flaws, the high-end of Mr. Ufolla’s range would be significantly lower than 10.3%.<sup>1087</sup>

Mr. Walters argues that Mr. Ufolla erroneously included Chesapeake Utilities, NiSource, and UGI Corporation.<sup>1088</sup> He asserts that Chesapeake Utilities should have been excluded because neither it, nor its utility subsidiaries have credit ratings and because it acquired Florida City Gas, a natural gas utility on November 30, 2023, which transaction represents approximately 40% of its post-acquisition market capitalization and certainly affects its fundamental value.<sup>1089</sup> He adds that NiSource was also a party to a significant transaction involving the sale of a 20% stake in NIPSCO, which divestiture represents approximately 20% of NiSource’s market capitalization, affecting its

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<sup>1085</sup> 4 Tr 2592-2593.

<sup>1086</sup> 4 Tr 1414.

<sup>1087</sup> *Id.*

<sup>1088</sup> *Id.*

<sup>1089</sup> 4 Tr 1414-1415.

fundamental value.<sup>1090</sup> He states that UGI Corporation should have been excluded as it has significant foreign operations in Europe.<sup>1091</sup> He notes that Mr. Ufolla acknowledges that Staff typically eliminates companies on the basis of not have credit ratings and/or foreign investment, but that Mr. Ufolla stated that he included Chesapeake Utilities and UGI in this case due to the limited number of proxy company candidates at this time, even though the results for Chesapeake and UGI produced nominally higher outputs from the DCF and CAPM.<sup>1092</sup>

Mr. Walters states that had Mr. Ufolla excluded these results, Staff's average and median DCF results would have been 9.94% and 9.81%, reductions of 57 basis points and 20 basis points respectively.<sup>1093</sup> Similarly, he adds that had Mr. Ufolla excluded these results from his CAPM analysis, Mr. Ufolla's his proxy group's average and median CAPM results would have been 9.73% and 9.59%, respectively, with the corrected CAPM average being 16 basis points lower than the 9.88% average he estimated, while the median is unchanged.<sup>1094</sup>

Mr. Walters states that Mr. Ufolla's proxy group has an average growth rate of 6.06%, which level of growth he asserts cannot be sustained in perpetuity as it is more than 46% higher than the expected long-term growth rate of the US Economy of 4.14%.<sup>1095</sup> Reiterating that no company can feasibly grow faster than the economy it operates in forever, he argues that had Mr. Ufolla performed a multi-stage DCF model

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<sup>1090</sup> 4 Tr 1415.

<sup>1091</sup> *Id.*

<sup>1092</sup> *Id.* Citation omitted.

<sup>1093</sup> *Id.*

<sup>1094</sup> *Id.*

<sup>1095</sup> 4 Tr 1416. Citation omitted.

that gives consideration to GDP growth, his DCF results would be significantly lower.<sup>1096</sup> He notes that he and Dr. Villadsen performed a multi-stage DCF analysis which gave consideration to the long-term GDP growth forecast.<sup>1097</sup>

### **Recommended ROE**

In reviewing the different analyses and evidence presented by the witnesses, and mindful of the standards set forth in *Bluefield* and *Hope, supra*, this PFD finds that DTE's recommended return of 10.25% is excessive, is contrary to the *Bluefield* and *Hope* standards, is unsupported by the record evidence, and thus should be rejected.

The first Supreme Court standard for authorizing a fair and reasonable ROE is that the return "should be commensurate with returns on investments in other enterprises having corresponding risks", but that the utility has "no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."<sup>1098</sup> As such, DTE, Staff, and the Attorney General, each chose a proxy group of comparable publicly-traded gas utilities, to which they applied various models to approximate comparable returns for DTE. ABATE and CUB used DTE'S gas proxy group, albeit with some changes.

The parties disagree regarding the inclusion of four companies within the various proxy groups: Chesapeake Utilities, NiSource Southwest Gas, and UGI.

ABATE asserts that Chesapeake should be excluded as it does not have a credit rating from S&P or Moody's.<sup>1099</sup> This PFD notes that DTE and Staff – both of whom

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<sup>1096</sup> *Id.*

<sup>1097</sup> *Id.*

<sup>1098</sup> *Hope, supra*, at 603; *Bluefield, supra*, at 692-693.

<sup>1099</sup> 4 Tr 2474; 4 Tr 1621-1622.

included Chesapeake in their proxy groups – acknowledge that they generally consider having a credit rating as a requisite criterion.<sup>1100</sup>

ABATE asserts that NiSource and Southwest should be excluded for being parties to significant merger and acquisition (“M&A”) activities. Mr. Walters notes that Dr. Villadsen kept these two in her proxy group even though significant M&A activity was a screening criteria Dr. Villadsen used to develop her proxy group.<sup>1101</sup> This PFD notes that Staff and the Attorney General also assert that Southwest should be excluded for the same reason.<sup>1102</sup>

This PFD notes that DTE indicates that both Chesapeake and Southwest are labeled “Mostly Regulated” – as opposed to “Regulated” – with less than 80% of assets regulated.<sup>1103</sup>

ABATE and the Attorney General assert that UGI should be excluded due to its extensive foreign investments.<sup>1104</sup> Mr. Walters notes that Staff typically eliminates companies with significant foreign investments but included UGI despite admitting that the DCF and CAPM model results for UGI produced nominally higher outputs.<sup>1105</sup> Indeed, this PFD also notes that Staff’s DCF and CAPM calculations for UGI and Staff’s DCF calculations for NiSource are outliers, well outside of the ranges of its other DCF and CAPM results. See Ex. S-4, Sch D-5, p. 5, 6.

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<sup>1100</sup> 4 Tr 2474; 4 Tr 1621-1622.

<sup>1101</sup> 4 Tr 1362.

<sup>1102</sup> 4Tr 1622, 4 Tr 1494-1495.

<sup>1103</sup> 4 Tr 2476.

<sup>1104</sup> 4 Tr 1415; 4 Tr 1495.

<sup>1105</sup> 4 Tr 1415. Citation omitted

For these reasons this PFD agrees that Chesapeake, NiSource, Southwest and UGI are not appropriate proxy companies. As such, this PFD shall adjust the parties' DCF and CAPM model estimate averages excluding the results for these companies.<sup>1106</sup> See, discussion, *infra*.

DTE also used a proxy group made up of regulated water utilities. 4 Tr 2472. Staff asserts that the water utility proxy group should be disregarded because water utilities do not face the same risks as gas utilities and because Dr. Villadsen states that her ROE recommendation only relies on her gas proxy group.<sup>1107</sup> Similarly, Mr. Coppola states that inclusion of water utilities is inappropriate as there are significant structural differences between gas utilities and water companies.<sup>1108</sup> This PFD agrees. As it did the Commission in DTE's recent rate case. See, Case No. U-20940, order, December 9, 2021, p. 91:

The Commission concurs with the ALJ's observation that "the Commission has consistently taken a traditional approach to establishing ROE, focusing on the most commonly used, fundamental approaches to determining a just and reasonable ROE, consistent with the principles of *Hope Natural Gas* and *Bluefield Waterworks*." Accordingly, the Commission agrees with the ALJ that water utilities are not appropriately included in a proxy group for determining an appropriate ROE for a gas utility.<sup>1109</sup>

Accordingly, the ROE estimates for DTE's water proxy companies shall not be considered.

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<sup>1106</sup> The Attorney General's DCF estimates included a result for Spire of 12%. Ex. AG-24. This estimate is well outside of the range for her other DCF results (8% - 9.9%), such that the Spire DCF result is rejected as an outlier.

<sup>1107</sup> 4 Tr 1622. Citation omitted.

<sup>1108</sup> 4 Tr 1496.

<sup>1109</sup> Citation omitted.

The parties made the following ROE recommendations: DTE 10.25% with a range of 10.0% - 10.7%;<sup>1110</sup> Staff 9.80% with range of 9.30% - 10.30%;<sup>1111</sup> the Attorney General 9.85% with a range of 9.51% - 10.42%;<sup>1112</sup> ABATE 9.45% with a range of 9.10% - 9.80%;<sup>1113</sup> and CUB 9.46% with a range of 8.9% - 9.14%.<sup>1114</sup> This PFD notes that some of the parties' ranges do not appear to be based on or have any correlation to the results of the models used. In addition, as discussed, *infra*, most of the parties' model results were based on including improper proxy companies or making improper adjustments. As such, this PFD does not consider the asserted ranges to lend any independent support for the determination of a reasonable ROE.

FLO did not make a specific ROE recommendation but asserts that the utility industry is overcompensated, that DTE is seeking a higher ROE than its cost of capital, and that, the Commission should reject DTE's proposed increased ROE and consider reducing the ROE.<sup>1115</sup> Ann Arbor does not make a specific ROE recommendation but asserts that an ROE lower than the one recommended by DTE would be sufficient to allow DTE to mitigate risk and provide an opportunity for reasonable shareholder returns.<sup>1116</sup>

DTE, Staff, the Attorney General, ABATE, and CUB each applied the Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow (DCF) model. DTE, Staff, the

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<sup>1110</sup> 4 Tr 2449. While Dr. Villadsen states that while she recommends that DTE be allowed to earn a 10.25% ROE, she states that is appropriate and reasonable to place DTE's allowed return at 10.35%, which is the middle of her overall range.

<sup>1111</sup> 4 Tr 1632

<sup>1112</sup> 4 Tr 1494, 1512; Ex. AG-23. Mr. Coppola used a 50% weight for his DCF results and 25% for each of the other two methods, resulting in a weighted average of 9.81% which he rounded up to 9.85%.

<sup>1113</sup> 4 Tr 1391.

<sup>1114</sup> 4 Tr 957. The average of Mr. Bandyk's DCF and CAPM analyses is 9.10%, and his recommended ROE is the average of his DCF and CAPM average and DTE's 9.90% ROE authorized in its last rate case.

<sup>1115</sup> 4 Tr 1391.

<sup>1116</sup> 3 Tr 519.

Attorney General and ABATE each also applied a Risk Premium model. DTE separately applied an Empirical Capital Asset Model (ECAPM). Staff, the Attorney General, ABATE and CUB take issue with DTE's use of ECAPM, and CUB rejects the use of the projected Risk Premium model. Also, various parties take issue with some of the inputs and adjustments used for the various models.

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.<sup>1117</sup> These adjustments were made pursuant to the application of an after-tax weighted average cost of capital (ATWACC) approach and the so-called Hamada approach.<sup>1118</sup> Staff, the Attorney General, and ABATE disagree with these adjustments. Mr. Ufolla states that the ATWACC approach has never been approved by this Commission.<sup>1119</sup> Mr. Coppola states that the ATWACC approach involves a "complex process of calculations" in order to "drive an upward adjustment of the final ROE rate."<sup>1120</sup> Mr. Walters states that the ATWACC methodology is poor regulatory police and which artificially increases rates to produce an excessive ROE opportunity for utility investors.<sup>1121</sup> Staff, the Attorney General and ABATE asserted that these adjustments significantly increase DTE's CAPM and DCF estimates.<sup>1122</sup>

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<sup>1117</sup> 4 Tr 2455.

<sup>1118</sup> Id.

<sup>1119</sup> 4 Tr 1624.

<sup>1120</sup> 4 Tr 1500

<sup>1121</sup> 4 Tr 1395.

<sup>1122</sup> 4 Tr 1629; 4 Tr 1500, 1504-1505; 4 Tr 1393-1394, 1398-1399.

Dr. Villadsen acknowledges that the Commission disagrees with her financial leverage adjustments, stating that while she reports results from her “Financial Risk Adjusted Method” in her workpapers, she ignores those results in her summary because “the Commission in the past has been critical of the approach.”<sup>1123</sup>

Staff, the Attorney General, and ABATE 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:

The Commission concurs with the ALJ’s observation that “the Commission has consistently taken a traditional approach to establishing ROE, focusing on the 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, this PFD finds that DTE’s financial leverage adjustments shall not be considered. However, Dr. Villadsen made DCF and CAPM calculations without applying financial leverage adjustments, the results of which shall be considered.

Regarding the CAPM estimates, the parties use different inputs for this calculation, with the most significant disagreements being over what is the proper market risk premium (MRP) input. Dr. Villadsen used two MRP’s – an historical average premium of market returns over income returns (7.17%) – and a Bloomberg’s forward-looking MRP

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<sup>1123</sup> 4 Tr 2485, n.80;  
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estimate (5.72%).<sup>1124</sup> Dr. Villadsen asserts that her historical MRP estimate of 7.17% to be more reasonable as it compares favorably with the results of her calculations of FERC forward-looking approach.<sup>1125</sup> Mr. Coppola used the same 7.17% MRP that Dr. Villadsen uses, albeit from a different source, and states that both of the MRP inputs used by Dr. Villadsen are reasonable.<sup>1126</sup> Mr. Walters derived multiple MRP estimates derived from a risk premium approach and a DCF approach, with his estimates ranging from 5.5%-8%.<sup>1127</sup> Asserting that historical estimates are flawed, Mr. Bandyk used the average of an implied equity risk premium, the average U.S. market risk premium by the 2023 IES Business School survey, and the 2023 U.S.ERP from Kroll (5.14%).<sup>1128</sup>

This PFD finds that the parties different market risk premium inputs included in their CAPM calculations to be reasonable and supported. In that regard, this PFD notes that FERC appears to recognize the use of both the historical and forward-looking CAPM analyses.<sup>1129</sup> Accordingly, this PFD finds that the parties' CAPM estimates should be considered.

DTE also performed an Empirical CAPM (ECAPM) calculation which includes an adjustment to CAPM.<sup>1130</sup> Mr. Ufolla disagrees with the use of the ECAPM in conjunction with adjusted betas.<sup>1131</sup> Similarly, Mr. Coppola states that DTE's ECAPM results were

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<sup>1124</sup> 4 Tr 2480.

<sup>1125</sup> Id.; Ex. A-14, Sch.D5.17.

<sup>1126</sup> 4 Tr 1504-1505.

<sup>1127</sup> 4 Tr 1384-1387.

<sup>1128</sup> 4 Tr 959-960.

<sup>1129</sup> FERC Opinion 569, 169 FERC 61129 (2019), par. 239 (“[I]n the CAPM model . . . [t]he expected market return can be estimated either using a backward-looking approach based upon realized market returns during a historical period, a forward-looking approach applying the DCF model to a representative market index, such as the S&P 500, or a survey of academics and investment professionals.”)

<sup>1130</sup> 4 Tr 2483.

<sup>1131</sup> 4 Tr 1628.

developed using the flawed Hamada methodology, that the ECAPM is not widely accepted as a cost of equity methodology among regulatory commissions in the United States, and that the use of the 30-year treasury rate as the risk-free rate in CAPM method resolves the need to use the ECAPM method.<sup>1132</sup> Mr. Walters states that Dr. Villadsen's use of an adjusted beta within her ECAPM calculations is inconsistent with ECAPM methodology and for which there is no legitimate basis for its use.<sup>1133</sup> Mr. Bandyk did not perform an ECAPM calculation, noting that Staff has historically rejected the ECAM method as part of the ROE analyses in rate cases.<sup>1134</sup>

This PFD notes that DTE has not identified an order whereby the Commission has previously recognized the use of the ECAPM model, and this ALJ is unaware of any. In addition, it is noted that FERC does not recognize the use of ECAPM, which it considers to be an "obscure" and "more controversial" variant of CAPM.<sup>1135</sup> More significantly, this PFD notes that the Commission "has consistently taken a traditional approach" to establishing ROE, focusing on the "most commonly-used, fundamental approaches" to determining a just and reasonable ROE.<sup>1136</sup> Accordingly, this PFD finds that DTE's ECAPM estimates should not be considered.

Regarding the DCF method, the parties calculated estimated ROEs using versions of two DCF methods: the single-stage DCF, which is based on the perpetual expected

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<sup>1132</sup> 4 Tr 1505-1506.

<sup>1133</sup> 4 Tr 1401-1403.

<sup>1134</sup> 4 Tr 962. Citations omitted.

<sup>1135</sup> See, Initial Decision, 153 FERC P 63027 (2015), par. 332 ("This Initial Decision will not consider the ECAPM in determining the proper Base ROEs for the MISO TOs. The quote from New Regulatory Finance suggests that at this time the ECAPM is relied upon by no more than a few 'financial scholars.' . . . There is no need to include an obscure, and arguably more controversial, variant of that pricing model."). It is noted that pursuant to several recent opinions, FERC has conducted a comprehensive assessment of the various models for establishing an ROE and that FERC does not include ECAPM within its acceptable models. See, discussion, *infra*.

<sup>1136</sup> Case No. U-20940, Order, December 9, 2021, p. 91.

future growth rate of dividends, and the multi-stage DCF, which is based on dividend growth tapering toward the growth rate of overall economy.<sup>1137</sup>

Dr. Villadsen performed two DCF analyses: a single-stage DCF model based on a perpetual expected future growth rate of dividends and a multi-stage DCF model with an initial rate of earnings growth followed by growth tapering toward the growth rate of the overall economy.<sup>1138</sup> Dr. Villadsen asserts that the single-stage DCF estimates merit more weight than the multi-stage DCF estimates as the forecasted long-term GDP growth rate is low and it is plausible that a company reaches steady-state growth.<sup>1139</sup>

Staff's DCF calculation used a single-stage approach, with an average of 5-year growth rates applied.<sup>1140</sup> The Attorney General's DCF calculation also used a single-stage approach, with an average of three 5-year earnings growth projections.<sup>1141</sup>

ABATE conducted three DCF model calculations: a constant growth DCF, a sustainable growth DCF and a multi-stage growth DCF model, each using varying growth rates.<sup>1142</sup> Mr. Walters asserts that the average long-term growth rate used is his constant growth rate DCF calculation (6.27%) is not realistic forward-looking projection, as the consensus of research finds that a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity.<sup>1143</sup> As such, he asserts that more weight should be given to the sustainable growth and multi-stage models of the DCF.<sup>1144</sup> Mr. Walters adds that Dr. Villadsen's Full Sample average growth rate projection (7.2%)

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<sup>1137</sup> 4 Tr 2486, 2487.

<sup>1138</sup> 4 Tr 2486-2487.

<sup>1139</sup> 4 Tr 2489, 2487.

<sup>1140</sup> Ex. S-4, Sch.D-5, p.4, 5.

<sup>1141</sup> 4 Tr 1498-1499; Ex. AG-24.

<sup>1142</sup> 4 Tr 1365-1366, 1368-1369, 1369-1373; Ex. AB-6 through Ex. AB-11.

<sup>1143</sup> 4 Tr 1367.

<sup>1144</sup> 4 Tr 1375.

exceeds her average growth rate of 3.9% for the U.S. economy by 85%, which he asserts defies logic.<sup>1145</sup>

This PFD notes that FERC requires a multi-stage DCF analysis in order to address the limitations of solely using a short-term growth rate, with the long-term growth rate based on the growth in gross domestic product.<sup>1146</sup> FERC's multi-stage analysis uses with the short-term growth rate having an 80% weighting and the long-term growth rate having a 20% weighting.<sup>1147</sup>

While the parties disagree on the weight to be given to the varying growth rates used, the PFD shall consider all DCF calculations made as both the single-stage and multi-stage DCF models are used and recognized.

DTE, Staff, the Attorney General and ABATE all used a Risk Premium approach, which estimates the ROE based on the historical relationship between allowed ROEs in utility at the time the ROEs were granted.<sup>1148</sup> Staff and intervenors are critical of Dr. Villadsen's Risk Premium method. Mr. Walters states that Dr. Villadsen's regression-derived risk premium estimates of 6.26% for gas utilities is significantly higher than the equity risk premiums realized in 2023, which he asserts suggests that her regression analysis overstates the cost of equity.<sup>1149</sup> Mr. Ufolla similarly disagrees with Dr.

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<sup>1145</sup> 4 Tr 1398.

<sup>1146</sup> FERC Opinion 569, 169 FERC 61129 (2019), par. 134. (“[T]he Commission's current policy is to require the DCF analysis of an individual company to include a projection of the long-term growth in dividends based on the growth in gross domestic product (GDP) . . .”); FERC Opinion 531, 147 FERC 61234 (2014), par. 38 (“Over the long-run, a regulated firm may reasonably be expected to grow at the rate of the average firm in the economy; growth either significantly above or below the growth of the economy as a whole is unlikely to continue indefinitely.”)

<sup>1147</sup> FERC Opinion 569-A, 171 FERC 61154 (2020), par. 209 (“[T]he long-term growth rate should be given 20% weighting and the short-term growth rate 80% weighting in the two-step DCF model.”).

<sup>1148</sup> 4 Tr 2489; 4 Tr 1630; 4 Tr 1507; 4 Tr 1376-1377.

<sup>1149</sup> 4 Tr 1404.

Villadsen's use of a regression analysis in her risk premium model, preferring the use of a more traditional risk premium model.<sup>1150</sup>

In its brief, MNSC notes that the ALJ in DTE Electric Company's last concluded rate case, U-21297, rejected Dr. Villadsen's use of the risk premium analysis, stating: "[t]his PFD also finds that the approach of performing a risk premium analysis based on a regression of the returns awarded by regulatory commissions relative to the treasury interest rate is not a compelling analysis, and should be rejected for the reasons explained by [Attorney General witness] Coppola . . ."<sup>1151</sup> MNSC states that in the testimony the ALJ referenced, Mr. Coppola had explained that the risk premium method falsely assumes "that treasury bond yields are the primary driver in ROE decisions by regulators;" that the method is "not connected to stock market performance and investor expectations of returns on investment;" and that utility commissions often base ROE decisions on "gradualism."<sup>1152</sup>

CUB argues that the Risk Premium model used by DTE should not be considered. Mr. Bandyk asserts that the Risk Premium model introduces into the ROE calculation the reliance on ROEs set by other regulatory commissions, and that the result of its application is divergent from the results from methods that are "underpinned by fundamental financial principles".<sup>1153</sup> Dr. Villadsen counters that, while the risk premium model is not underpinned by fundamental financial principles in the manner of the CAPM and DCF estimates, "this model is a useful approach as it takes into account the interest

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<sup>1150</sup> 4 Tr 1631.

<sup>1151</sup> MNSC initial brief, p. 42. Citation omitted.

<sup>1152</sup> *Id.*, p. 42-43. This PFD notes that Mr. Coppola does not appear to contest DTE's risk premium model results in this case.

<sup>1153</sup> 4 Tr 964.

rate prevailing during the quarter the decision that granted the ROE used in the analysis was issued.<sup>1154</sup>

This PFD notes that after an extensive analysis of a comprehensive record and arguments made, FERC rejected the use of the Risk Premium method, reasoning, in part, as follows:

As an initial matter, the Risk Premium model is largely redundant with the CAPM. Although they rely on different data sources to determine the risk premium, both models use indirect measures (i.e., past Commission orders in the Risk Premium model and S&P 500 data in the CAPM) to ascertain the risk premium that investors require over the risk-free rate of return. We find that using the Risk Premium model in conjunction with the CAPM model would confer too much weight towards risk premium methodologies. The Commission has long used and, over time, refined the DCF model and we find that it would be inappropriate for variations of the risk premium model to receive twice its weight. In light of the disadvantages of the Risk Premium model discussed below and the similarity of the CAPM and Risk Premium models, we find that it is more appropriate to use only the CAPM to provide a risk premium-based cost of equity estimate.<sup>1155</sup>

In its order, FERC identified various of the disadvantages with the Risk Premium model, including that a) the Risk Premium model is likely to provide a less accurate current cost of equity estimate than the DCF model or CAPM because it relies on previous ROE determinations, b) circularity is particularly direct and acute because the model directly relies on past Commission ROE decisions, c) there was insufficient evidence to conclude that investors rely on risk premium analyses utilizing historic Commission ROE determinations or settlement approvals to determine the cost of capital and make investment decisions, and d) the Risk Premium methodology also entails numerous judgement calls and ambiguity, and thus corresponding points of dispute among parties

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<sup>1154</sup> 4 Tr 2491

<sup>1155</sup> FERC Opinion 569, 169 FERC 61129 (2019), par. 341.

that would render the model results less predictable and transparent than the CAPM and DCF model.<sup>1156</sup>

This PFD acknowledges that in its Opinion 569-A, FERC changed course and concluded that, with certain modifications, the Risk Premium model again was appropriate to use to estimate a reasonable ROE.<sup>1157</sup> This PFD also notes that on appeal Opinion 569-A was set aside precisely because FERC failed to offer a reasoned explanation for its decision to reintroduce the Risk Premium model “after initially, and forcefully, rejecting it”, with the Court of Appeals noting that in FERC Opinion 569, FERC “spent several pages demonstrating the ‘impressive extent of [that model’s] deficiencies’”, such that FERC found the Risk Premium model “quite defective”.<sup>1158</sup>

This PFD finds Mr. Bandyk’s and FERC’s reasoning in Opinion 569 rejecting the Risk Premium model persuasive. However, as the Commission previously has considered Risk Premium model results, this PFD concludes that it would be premature to reject the use of this model in this case before Staff and other intervenors (other than CUB) have addressed the reasons offered by FERC for rejecting the use of this model. This PFD recommends that the Commission direct the parties in DTE’s next rate cases to address whether this model remains an appropriate method for determining an ROE. This PFD agrees with that DTE’s regression-derived Risk Premium estimate is inflated and thus should not be considered.

The parties take issue with other aspects of the models used by other parties and the inputs therein. However, these differences do not appear to affect the results as

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<sup>1156</sup> *Id.*, par. 342, 343, 345, 346, 350.

<sup>1157</sup> FERC Opinion 569-A, 171 FERC 61154 (2020), par. 104.

<sup>1158</sup> *MISO Transmission Owners v. FERC*, 45 F.4th 248, 263, 264 (CA DC Cir. 2022).

significantly as the differences discussed, *supra*, or are considered moot as a result of the model results being otherwise rejected. Moreover, this PFD notes that the Commission has stated that the determination of a fair and reasonable ROE “is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved.”<sup>1159</sup> Thus, this PFD concludes that these other differences regarding the appropriate use of other models and inputs need not be resolved in this case.

In sum, the averages of the accepted ROE estimates generated from the parties’ methods as applied to the corrected proxy groups are as follows:

- 9.5% DTE DCF (adjusted) <sup>1160</sup>
- 9.4% DTE CAPM (adjusted) <sup>1161</sup>
- 9.9% Staff DCF <sup>1162</sup>
- 9.7% Staff CAPM <sup>1163</sup>
- 9.1% Staff Risk Premium (average) <sup>1164</sup>
- 9.1% Attorney General DCF <sup>1165</sup>
- 10.5% Attorney General CAPM <sup>1166</sup>
- 9.8% Attorney General Risk Premium <sup>1167</sup>
- 9.5% ABATE DCF <sup>1168</sup>

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<sup>1159</sup> *Meridian Twp v City of East Lansing*, 342 Mich 734, 749, 71 NW2d 234 (1955).

<sup>1160</sup> Average of single- and multi-stage results. Ex. A-14, Sch. D5.6, p. 1, 2.

<sup>1161</sup> Average of long-term MRP inputs. Ex. A-14, Sch. D5.11, p. 1, 2.

<sup>1162</sup> Ex. S-4, Sch. D-5, p. 5.

<sup>1163</sup> Ex. S-4, Sch. D-5, p. 6.

<sup>1164</sup> Ex. S-4, Sch. D5, p. 10.

<sup>1165</sup> Average excluding Spire results (12%) as outlier of range (8% - 9.9%). Ex. AG-24.

<sup>1166</sup> Ex. AG-25.

<sup>1167</sup> Ex. AG-26.

<sup>1168</sup> Average 4 Tr 1376.

9.6% ABATE CAPM <sup>1169</sup>

9.9% ABATE Risk Premium <sup>1170</sup>

9.1% CUB DCF <sup>1171</sup>

9.0% CUB CAPM <sup>1172</sup>

The average of these estimates is 9.50%, with a range of 9.0% - 10.5%.

Staff, the Attorney General, and ABATE each offered consistent evidence of recently authorized ROE's for gas utilities rendered by other state commissions across the country for 2022 and 2023. Mr. Ufolla states that the average authorized decisions for 2022 was 9.53% and the average in 2023 was 9.64%.<sup>1173</sup> Mr. Coppola asserts that for most of the other gas utilities with risks comparable to DTE gas, the ROE rates have averaged around 9.5% in the past two years.<sup>1174</sup> He adds that only two of the 33 ROE decisions in 2022 and only three of the 36 ROE decisions in 2023 are at rates of 9.9% or higher.<sup>1175</sup> He states that the higher rates are from California, which is challenged with wildfires and earthquakes, Florida relating to small utility companies, and Michigan.<sup>1176</sup> Mr. Walters summarizes the distribution of authorized ROEs since 2016.<sup>1177</sup> His summary shows the following averages for the last four years: 2020 (9.4%), 2021 (9.5%), 2022 (9.5%), and 2023 (9.6%).<sup>1178</sup>

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<sup>1169</sup> Average 4 Tr 1390.

<sup>1170</sup> Average 4 Tr 1382.

<sup>1171</sup> Adjusted to gas sample Ex. A-14, Sch. D5.8, p. 1; 4 Tr 957.

<sup>1172</sup> Ex. CUB-7.

<sup>1173</sup> 4 Tr 1631-1632, citing S&P Global: RRA Focus Major Rate Case Decisions (Ex. S-4, Sch. D-5, p.11).

<sup>1174</sup> 4 Tr 1509; Ex. AG-29.

<sup>1175</sup> *Id.*

<sup>1176</sup> *Id.*

<sup>1177</sup> 4 Tr 1338-1339.

<sup>1178</sup> *Id.*

On rebuttal, Dr. Villadsen states that the average ROE for gas utilities for 2024 (through May 20, 2024) is 9.9%.<sup>1179</sup> However, the only support Dr. Villadsen offers for his assertion is his own graph without data points or other information. Unlike Mr. Coppola's Ex. AG-29, Dr. Villadsen does not provide information regarding the dates of the rate orders, the name and location (state) of the utility, and the specific rates which make up the asserted average, with which the other parties, this ALJ and ultimately the Commission can assess whether there are any outliers which might by unduly be influencing the average. Thus, this PFD finds that Dr. Villadsen's statement of the average ROE for gas utilities for 2024 through May, 2024 is unsupported.

This PFD finds that consideration of recently authorized ROEs is appropriate, as the Commission previously has considered other ROEs and has stated that it will continue to do so. See, Case No. U-20940, Order, December 9, 2021, p. 89, 91 (“[T]he Commission considers other ROEs and notes that the authorized ROEs for gas utilities in other states may have declined. . . . [T]he Commission notes that it will continue to compare ROE for DTE to other approved benchmarks including . . . the approved ROEs for comparable utility peers.”). Indeed, comparing authorized ROEs for regulated utilities is reasonable and necessary, as the Supreme Court's standard expressly provides that equity returns should be “commensurate with returns on investments having corresponding risks,” and other regulated utilities are the businesses with the most closely corresponding limited risks to those of DTE.

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<sup>1179</sup> 4 Tr 2589.  
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This PFD finds that the average of recently authorized ROEs from other states is 9.5%, with a range of 9.2% - 9.8%%.<sup>1180</sup>

Mr. Bandyk argues that under the standards established by the Supreme Court in *Bluefield* and *Hope*, a return that is authorized above the amount “commensurate with returns on investments in other enterprises having corresponding risks” will cause the utility’s customers to be overcharged and lose wealth relative to what they would be charges with a lower and more appropriate return.<sup>1181</sup> He asserts that in that circumstance, that wealth is transferred from customer’s to the utility holding company’s shareholders.<sup>1182</sup>

Mr. Bandyk adds that there is strong evidence that public regulatory commissions on average have tended to set electric utility ROEs above those derived from using the widely accepted methods for estimating ROE.<sup>1183</sup> He asserts that testimony first filed in Case No. U-20836 shows that a comparison of the average ROE for U.S. stocks as a whole since 1990 to the authorized ROE’s for regulated electric and gas utilities over the same time period indicates that the average authorized ROEs have been consistently above the market-based ROEs by approximately two percentage points in almost every year for over thirty years.<sup>1184</sup> He references a 2023 article which states

[t]here is mounting evidence that investment in utility stocks has outperformed the broader market in the past and will continue to do so. Regulated utilities are less risky than competitive industries, and therefore are supposed to produce a lower total return over time.<sup>1185</sup>

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<sup>1180</sup> See Ex. AG-29; 4 Tr 1339, Table CCW-1.

<sup>1181</sup> 4 Tr 951.

<sup>1182</sup> *Id.*

<sup>1183</sup> 4 Tr 952.

<sup>1184</sup> 4 Tr 953, citing Case No. U-20836, Dkt-0479. Direct Testimony of David J. Garnett, 8 Tr 3880.

<sup>1185</sup> 4 Tr 953-954; Ex. CUB-5, p.1.

The article also references projections that the long-term total return for the broader market will be around 7%.<sup>1186</sup> Mr. Bandyk adds that academics have noted a growing premium of regulatory commission-authorized ROEs over the rate of return on long-term treasury bonds (risk free rate) that cannot statistically be explained by financial fundamentals.<sup>1187</sup>

Similarly, Mr. Koeppel states that a 2023 study found that utilities charged customers billions in excess costs each year as a result of rates of return being higher than the utilities' cost of capital.<sup>1188</sup> This PFD notes that the study estimates that "utilities current regulated returns on equity are significantly higher than various benchmarks would suggest."<sup>1189</sup>

Mr. Bandyk states that a higher return implies higher risk, so that the empirical result that awarded ROEs are higher than market returns would suggest that regulated utilities are riskier investments than the market as a whole.<sup>1190</sup> Mr. Bandyk asserts the "noncontroversial fact" that regulated utilities are much less risky than the market as a whole.<sup>1191</sup>

This PFD agrees. Indeed, that regulated utilities are much less risky than other businesses is without question. As S&P succinctly states, the regulated utility industry is "very low risk" as it "provides indispensable services that are strategically important to economies, have material barriers to entry, and essentially operate as a monopoly

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<sup>1186</sup> Ex. CUB-5, p. 2. Citations omitted.

<sup>1187</sup> 4 Tr 954, citing David Rode and Paul Fischbeck. "Regulated equity returns: A puzzle." Energy Policy, Oct. 2019 ("This growing premium does not appear to be explained by traditional asset-pricing models, often in direct contrast to regulators' stated intent... However, absent some normative justification for this premium, it would appear that regulators are authorizing excessive returns on equity to utility investors.")

<sup>1188</sup> 4 Tr 1021; Ex. FLO-41.

<sup>1189</sup> Ex. FLO-41, p.2.

<sup>1190</sup> 4 Tr 954.

<sup>1191</sup> Id.

insulated from market challenges.”<sup>1192</sup> See, also, *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19, 48-49, 29 S. Ct. 192 (1909) where the Supreme Court, having stated that the “amount of risk in the business is a most important factor” in determining an adequate return for the utility, describes the minimal risk for New York’s gas company:

In an investment in a gas company, such as complainant's, the risk is reduced almost to a minimum. It is a corporation which . . . monopolizes the gas service of the largest city in America, and is secure against competition under the circumstances in which it is placed . . . An interest in such a business is as near a safe and secure investment as can be imagined with regard to any private manufacturing business . . .

See, also, *Bluefield*, 262 U.S. at 693 (“In *Wilcox*, the investment was held to be safe, returns certain and risk reduced almost to a minimum – as nearly a safe and secure investment as could be imagined in regard to any manufacturing enterprise.”)

In other words, public utilities like DTE have a captive customer base to which it sells necessary services (heat and power) while operating as a monopoly insulated from any competition from alternative vendors.

Indeed, as Mr. Bandyk and others note, the betas of regulated utility holding companies tend to be less than one, confirming that those stocks are less sensitive to changes in overall market returns.<sup>1193</sup>

Moreover, as regulated utilities are much less risky an investment than other businesses, regulated utilities are only entitled to returns that are lower than those earned by other businesses in the general market. Again, as the Supreme Court held in *Bluefield*,

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<sup>1192</sup> This characterization of the low-risk nature of the regulated utility industry was expressly affirmed by the Commission in a recent finding. See Case No. U-20836, Order, November 18, 2022, p. 231, 241; PFD, September 19, 2022, p. 449-450, quoting 8 Tr 3065.

<sup>1193</sup> 4 Tr 955.

a public utility is entitled to earn a return equal to that being made by businesses with “corresponding risks and uncertainties,” but it has “no constitutional right” to returns realized or anticipated in highly profitable enterprises or speculative ventures.”<sup>1194</sup> See, *also, Wilcox*, 212 U.S. at 49.

The less risk, the less right to any unusual returns upon the investments. One who invests his money in a business of a somewhat hazardous character is very properly held to have the right to a larger return, without legislative interference, than can be obtained from an investment in government bonds or other perfectly safe security.

Thus, it is axiomatic that under the Supreme Court standards a regulated utility’s authorized return must be less than the return being earned by the general market. The evidence presently in this case indicates that an authorized ROE of 9.50% -- the average of ROE’s authorized recently (see, discussion, *supra*) – is two percentage points above the recent historical returns for the general market. In addition, the evidence indicates that the projections for the long-term return for the general market will be around 7%.<sup>1195</sup>

This PFD notes that although Dr. Villadsen argues that the referenced study offered by Mr. Koepfel (Ex. FLO-41) is based on “several faulty premises”, DTE does not rebut the other evidence that authorized ROE returns for regulated utilities are well above general market returns, nor offer any contradicting evidence in that regard.<sup>1196</sup>

Thus, this PFD finds that there is a current imbalance of what is a reasonable ROE under the two parts of the applicable Supreme Court standard. Under this Supreme Court standard, an appropriate return needs to be commensurate with returns on investments in other businesses having corresponding risks (which return is approximately 9.5%),

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<sup>1194</sup> 362 U.S. at 692-693.

<sup>1195</sup> Ex. CUB-5, p. 2. This PFD notes that while these projections are somewhat dated, the projections are consistent with recent historical returns.

<sup>1196</sup> 4 Tr 2591.

while the return also should be no greater than the return being earned by the more risky, general market (which return is about 7%). Thus, a return of 9.5% and a return of 7% are both reasonable and excessive or insufficient at the same time depending upon which part of the standard is considered.

As such and finding that neither of the two parts of this standard should be ignored in favor of the other part, in order to best come close to satisfying these two parts of this standard, this PFD is compelled to find that the ROE should be set at 8% or 8.5%. However, authorizing a return in the 8% - 8.5% range likely is too drastic of a change to be made at once. Rather, a gradual change is more appropriate to let the market, DTE Energy's shareholders and the credit reporting agencies assess and adjust to the gradual change. Thus, this PFD finds that an authorized an ROE of 9.4% is reasonable and supported, as being just below ABATE's and CUB's recommended ROEs, and just below the average of recently authorized ROEs, while also moving 50 basis points below DTE's currently authorized ROE towards the returns for the general market. This PFD further finds that authorizing an ROE at DTE's currently authorized ROE or above would be directly contrary to both this applicable Supreme Court standard set forth in *Bluefield* and *Hope*, and the interests DTE's rate payers. In that regard, Mr. Walters states, "[i]t is critical that this Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity."<sup>1197</sup> See, also, *City of Detroit*, *supra*:

If the price of electricity can be reduced and still leave a reasonable return on the fair value of all property as required [by statute], then the commission has a duty to make such reductions in rates.<sup>1198</sup>

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<sup>1197</sup> 4 Tr 1344.

<sup>1198</sup> 308 Mich at 714 (dissent)

This PFD agrees.

The second Supreme Court standard for establishing a reasonable return on equity is that the return should be “sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.”<sup>1199</sup> This PFD finds that the record evidence in this case consistently supports a finding that the ROEs proposed by Staff, the Attorney General, ABATE, and CUB as well as the ROEs supported by the record evidence in this case are each more than sufficient for DTE to maintain its credit and attract capital.

The financial integrity of DTE’s business and its ability to maintain its credit and attract capital are directly a function of DTE’s lack of risk as a regulated utility. In that regard, as discussed, *supra*, the Supreme Court, the credit reporting agencies and this Commission have all recognized that the regulated utility industry is very low risk.<sup>1200</sup>

Commensurate with the low-risk nature of the regulated utility industry, DTE’s current credit ratings from the three main credit reporting agencies – Moody’s, S&P, and Fitch – have consistently been within the middle levels of the multiple levels of credit ratings categories, with each level of ratings category being “investment grade.”<sup>1201</sup> Similarly, the Commission recognizes DTE’s credit rating as “healthy”.<sup>1202</sup>

“Investment grade” refers to the group of credit ratings that indicate a low default risk.<sup>1203</sup> As such, companies with investment grade credit rating will issue debt at a lower

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<sup>1199</sup> *Hope*, 320 U.S. at 603.

<sup>1200</sup> *Bluefield*, *supra*; 4 Tr 1357 quoting S&P September 2023 report; Case No. U-20836, Order, November 18, 2022, p. 231, 241, PFD, September 19, 2022, p. 449-450, quoting 8 Tr 3065.

<sup>1201</sup> Ex. A-17, Sch. G1.

<sup>1202</sup> Case No. U-20940, Order, December 9, 2021, p. 78 (“The Commission finds that the new Moody’s rating [for DTE] places the company six notched above the lowest investment grade rating, which is still a healthy credit rating.”)

<sup>1203</sup> See, *Bankinter Financial Dictionary*, Investment grade.

interest rate than others with a poorer credit rating, allowing them to obtain financing more cheaply.<sup>1204</sup> As the term suggests, companies within this rated grouping are each suitable for “investment” purposes, including for the attraction of capital through stock and bond issuances and maintaining credit through borrowing from lenders. Thus, even if DTE’s credit rating were to be downgraded one rating level based on the equity ratio and/or ROE set by the Commission – and there is no record evidence which suggests that may occur – DTE would still have a “healthy” investment grade credit rating which ensures the maintenance of its credit and its ability to attract capital.

Mr. Walters states that the market’s assessment of a company’s investment risk is generally described by credit rating analysts reports and notes that DTE’s current credit ratings are A- and A3 from S&P and Moody’s, respectively.<sup>1205</sup> He adds that S&P’s September 2023 report on DTE states that S&P’s assessment of DTE’s business risk profile reflects DTE’s “very low-risk, regulated gas utility operations, very large customer base, and effective regulator risk management, and that S&P assesses DTE “in the upper-half of its business risk profile category compared to peers.”<sup>1206</sup> He states that S&P’s report indicates that DTE on balance has over earned its allowed ROE over the last several years.<sup>1207</sup>

Dr. Villadsen counters that these credit ratings aspects have “no bearing on the cost of equity”, such that Mr. Walters’ assertion that DTE’s credit rating has implications for the riskiness of its ROE is “unfounded.” This PFD disagrees. Indeed, the credit report excerpt Dr. Villadsen quotes specifically states that credit ratings “speak to one aspect of

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<sup>1204</sup> *Id.*

<sup>1205</sup> 4 Tr 1357.

<sup>1206</sup> *Id.* Citation omitted.

<sup>1207</sup> 4 Tr 1358-1359.

an investment decision.”<sup>1208</sup> Moreover, Dr. Villadsen’s assertion is directly contradicted by Mr. Lepczyk, another DTE witness, who states that “[t]o help investors determine where they will invest, investors rely on credit rating agencies and their own credit analysis to determine the relative risks between utility opportunities.”<sup>1209</sup>

Mr. Coppola states that DTE’s access to the capital markets is strong as evidenced by DTE Gas issuing \$295 million of 7-year and 12-year long-term debt with rates ranging from 5.57% to 5.73% in October 2023.<sup>1210</sup> He also notes that DTE Electric issuing \$2.9 billion of 5-year to 30-year long-term debt at rates ranging from 5.57% to 5.73% at various times in 2023.<sup>Id.</sup>

Mr. Coppola states that several gas utilities have accessed capital markets at competitive interest rates since receiving an ROE near or below the average ROE of 9.5%.<sup>1211</sup> He asserts that the fact that DTE needs to raise capital because of a large capital investment program is not unique to DTE, as other gas utilities face the same issues and are able to raise capital with ROE’s of 9.85% or below.<sup>1212</sup>

Mr. Coppola states that there is no evidence equity investors have abandoned utilities that have been granted ROEs below DTE’s currently authorized ROE of 9.9%.<sup>1213</sup> Indeed, he asserts that stock investors continue to migrate to utility stocks.<sup>1214</sup>

Mr. Walters concurs. He asserts that utilities have been able to access external capital to support capital expenditure programs.<sup>1215</sup> He states that the capital investments

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<sup>1208</sup> 4 Tr 2588. Citation omitted.

<sup>1209</sup> 4 Tr 2192.

<sup>1210</sup> 4 Tr 1508.

<sup>1211</sup> 4 Tr 1509-15100; Ex. AG-29.

<sup>1212</sup> *Id.*

<sup>1213</sup> 4 Tr 1510. Indeed, he asserts that stock investors continue to migrate to utility stocks.

<sup>1214</sup> *Id.*

<sup>1215</sup> 4 Tr 1341.

are enhancing shareholder value and are attracting both equity and debt capital to fund capital investments.<sup>1216</sup> Mr. Walters argues that the robust valuations of regulated utility equity securities is a strong signal that regulated utilities can access equity capital under reasonable terms and conditions, and at relatively low cost.<sup>1217</sup>

Dr. Villadsen asserts that if a lower than 51.5% equity ratio is mandated for DTE – as discussed, *supra*, this PFD recommends a 50% equity ratio – then DTE’s ROE should be set higher than the 10.25% he recommends.<sup>1218</sup> This PFD disagrees. As discussed, *supra*, the factors that the Commission considers in assessing a reasonable equity ratio and the factors that the Commission considers in assessing a reasonable ROE are not the same. In addition, the Commission has not agreed to the linkage between equity balance and ROE that DTE proposes.

Dr. Villadsen asserts that utilities rely on investors in capital markets to provide funding for their capital expenditures, such that it is important to consider how investors view the current economic conditions.<sup>1219</sup> Dr. Villadsen asserts that, although measures of market volatility are slightly below long-term averages, the SKEW index (which measures the market’s willingness to pay for protection against sudden substantial downturns) shows that investors are cautious about.<sup>1220</sup> She adds that investors have seen several bank failures, the on-going war in Ukraine, unrest in the Middle East and an unprecedented mix of monetary tightening and fiscal stimulus.<sup>1221</sup> In that regard, Dr.

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<sup>1216</sup> 4 Tr 1343.

<sup>1217</sup> *Id.*; Ex. AB-4.

<sup>1218</sup> 4 Tr 2496.

<sup>1219</sup> 4 Tr 2471.

<sup>1220</sup> 4 Tr 2466.

<sup>1221</sup> *Id.*

Villadsen states that recent surveys by economists indicate that U.S. inflation will be 4.1% in 2023 and 2.7% in 2024.<sup>1222</sup>

Mr. Coppola counters that stock market volatility should not be a consideration in establishing a fair ROE for DTE. As Mr. Coppola states, the stock market has historically been very volatile, and the Commission's focus in setting ROEs for utilities should be the long-term financial health of the utility not the short-term gyrations of the stock market.<sup>1223</sup> In addition, Mr. Coppola states that utility stocks are considered a "safe haven" for investors during times of uncertainty and volatility precisely because they are not as susceptible to volatility as the general stock market.<sup>1224</sup> Mr. Walters concurs, stating that the utility industry has been able to deliver generally positive and relatively stable returns during a period of elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world.<sup>1225</sup>

Dr. Villadsen asserts that when estimating the cost of equity, consideration must be given to two categories of risk: business risk, which she states is the degree to which generated cash flows vary in response to moves in the broader market, and financial risk, which she states is a function of how the business is financed.<sup>1226</sup> In this regard, Dr. Villadsen asserts that, although DTE is engaged in a similar line of business, has comparable credit ratings and has access to alternative regulatory mechanisms compared to the gas proxy companies, DTE has higher operating leverage than the gas

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<sup>1222</sup> 4 Tr 2470.

<sup>1223</sup> 4 Tr 1151

<sup>1224</sup> *Id.*

<sup>1225</sup> 4 Tr 1354.

<sup>1226</sup> 4 Tr 2451.

proxy companies.<sup>1227</sup> As such, she considers DTE’s business risk to be above the average compared to the gas proxy companies.<sup>1228</sup>

This PFD finds that Dr. Villadsen is misconstruing the relevant risk applicable to establishing a reasonable ROE under the Supreme Court standards. As discussed, *supra*, the Supreme Court held that the risk that is relevant in establishing an ROE is what credit reporting agencies describe as “business risk”; that is, the fact that regulated utilities provide necessary services (heat and power) to a captive customer base while operating as a monopoly insulated from competition from other vendors.<sup>1229</sup> Further, the Supreme Court held that this business risk is relevant to establishing a reasonable ROE by serving as a benchmark for determining those businesses with commensurate risk to whose returns the utility’s returns should be comparable.<sup>1230</sup>

Conversely, the Supreme Court makes clear that the relevant risk for purposes of establishing a reasonable ROE is not the financial risk the Dr. Villadsen describes. As the Supreme Court stated in *Hope*, “regulation does not insure that the business shall produce net revenues.”<sup>1231</sup> In *Hope*, the Court was quoting from its prior opinion in *Federal Power Commission v. Natural Gas Pipeline of America*, 315 U.S. 575, 590 (1943), where the Court stated:

[T]he hazard that the property will not earn a profit remains on the company in the case of a regulated, as well as an unregulated business.

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<sup>1227</sup> 4 Tr 2495.

<sup>1228</sup> *Id.*

<sup>1229</sup> See, 4 Tr 1357, quoting S&P September 2023 report (“[DTE’s] utility operations provide indispensable services that are strategically important to economies, feature material barriers to entry, and essentially operate as a monopoly insulated from market challenges.”)

<sup>1230</sup> See, *Hope*, *supra*, at 603 (“[t]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.”)

<sup>1231</sup> 320 U.S. at 603.

Similarly, in *Bluefield*, the Court made clear that in assessing an adequate return, the Court is assuming that the utility is being operated “under efficient and economical management.”<sup>1232</sup> Thus, whether DTE has greater financial risk – through greater financial leverage that DTE’s management has taken on – is not informative in determining an appropriate ROE.<sup>1233</sup>

In addition, Dr. Villadsen’s assertion that unforeseen events may make access to capital markets problematic constitutes unsupported speculation. As such, it is improper for this PFD or the Commission to make a finding or a conclusion which simply adopts DTE’s unsupported, conclusory assertions that DTE may be at greater financial risk without substantial evidence supporting its assertion.<sup>1234</sup>

Moreover, in accordance with the Supreme Court’s and the Michigan courts’ dictates that the determination of a reasonable return requires the balancing of the interest of the utility investor and the customer, the impact that any market conditions or disruptions may have on DTE’s ratepayers must be considered. As the Commission has repeatedly stated, the rate of return “should not be so high as to place an unnecessary burden on ratepayers.”<sup>1235</sup> Indeed, this PFD notes that previously the Commission has

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<sup>1232</sup> 262 U.S. at 692-693 (“The return . . . should be adequate, under efficient and economical management, to maintain and support its credit . . .”)

<sup>1233</sup> This PFD notes that S&P states that, because of DTE’s low-risk, regulated utility business model, S&P considers DTE’s financial risk so low that it doesn’t use its standard benchmark that it typically uses for typical corporate issuers. See, 4 Tr 1358, n. 12, quoting S&P Global Ratings, RatingsDirect, DTE Gas Co., September 25, 2023 (“We assess DTEG’s financial risk profile using our low volatility table rather than the benchmark tables we use for typical corporate issuers.”)

<sup>1234</sup> See, *Consumers Power v. MPSC*, 78 Mich App 581, 585, 261 NW2d 10 (1977)(Under applicable statutory standards, findings of fact shall be accompanied by a concise and explicit statement of underlying facts supporting them; a conclusion of law shall be supported by authority or reasoned opinion; “merely conclusional statements” without independent and substantial evidence are insufficient.).

<sup>1235</sup> Case No. U-15244, Order, December 23, 2008, p. 12.

expressly taken the effects of the economy on ratepayers into account in denying a requested increased authorized ROE.

The poor Michigan economy has caused the utility's ratepayers as much or more hardship than it has the utility. Establishing an appropriate ROE requires the Commission to balance the interests of the utility with the interests of its ratepayers."<sup>1236</sup>

Finally, although not raised by any party in its testimony or briefs, this PFD notes the Commission's statement in its Order in Case No. U-18322, as follows:

The Commission also asks other parties to consider the degree of financial adjustment they are requesting the Commission to undertake in one proceeding, because it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions.<sup>1237</sup>

This PFD finds the Commission's quoted statement is problematic in several respects. First and foremost, the Commission's statement purports to establish a new standard for establishing a reasonable ROE which is in direct conflict with the Supreme Court's standards which are controlling.<sup>1238</sup> That is, the Supreme Court's standards for setting a reasonable ROE are based on whether the returns are associated with commensurate business risks and whether the return is sufficient to maintain the utility's credit and attract capital, not whether there has been a "radical change" in general "economic conditions."

Moreover, this purported alternative standard is unworkable, as its terms "significant change", "radical change" and "underlying economic conditions" are broadly

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<sup>1236</sup> Case No. U-15985, Order, June 3, 2010, p. 35.

<sup>1237</sup> 4 Tr 2403, quoting Case No. U-18322, Order, February 28, 2018, page 44.

<sup>1238</sup> *Michigan Public Utilities Commission v. Michigan State Telephone*, 228 Mich 658, 664, 200 N.W. 749 (1924)("These elements [of just compensation, including . . . a fair return upon the present value of the property used and useful in public service], when determined, measure the rate to be paid by the public for the service. Upon the issue of confiscation, a federal question, decisions of the Supreme Court of the United States are controlling.").

stated and undefined. In addition, application of this new standard has the practical effect of “locking in” for a current case an ROE previously authorized on evidence presented in a prior case, to the detriment of the party or parties asserting that evidence submitted in the current case supports a change from the prior ROE.

Suffice to say for purposes of this case, this PFD notes that the parties including DTE assert that there have been or may be meaningful changes in economic conditions, and thus, the conclusory, broadly-stated and undefined limitation suggested by the Commission’s statement – that it is not realistic to make a significant change in ROE – is inapplicable. As such, this PFD finds it appropriate to consider, in accordance with the Supreme Court standards, the evidence submitted, and arguments made, by the parties in this case in rendering its findings and recommendations to the Commission.

In summary, this PFD finds that the ROEs recommended by ABATE and CUB each are reasonable, supported by the accepted evidence and commensurate with returns on investments having corresponding risks, albeit at rates well above the returns currently garnered by riskier companies in the general market, and are in accord with the Supreme Court standards, while also finding that the ROEs recommended by DTE, Staff and the Attorney General are not. This PFD also finds that an authorized ROE of 9.40% is slightly below ABATE’s and CUB’s ROEs and the average of recent state authorized ROEs. This PFD further finds that an authorized ROE of 9.40% represents a gradual but necessary move toward the range of general market returns. This PFD further finds that the recommended ROE of DTE (10.25%) and DTE’s currently authorized ROE (9.90%) are well above such middle range and averages, and general market ROEs. This PFD further finds that the ROEs recommended by Staff and the intervenors as well as the ROE

recommended by this PFD each are more than sufficient for DTE to maintain its credit and attract capital, and that DTE's recommended ROE and current ROE are unnecessary to do so. Accordingly, this PFD recommends the Commission authorize an ROE of 9.40%.

### **Long-Term Debt Cost Rate**

DTE developed a projected long-term debt cost rate 4.44%.<sup>1239</sup> Mr. Lepczyk states that to calculate this cost, DTE starts with the actual December 31, 2022 long-term debt outstanding, with any known maturities were considered redeemed and any forecasted long-term debt issuances were added to arrive at the projected balance as of September 30, 2025.<sup>1240</sup> He adds that known issuances include \$295 million issued in October 2023, and forecasted long-term debt issuances of \$119 million in September 2024 and \$150 million in August 2025 were also added.<sup>1241</sup> He states that the 2024 and 2025 debt issuances are assumed to be 30-year fixed rate bonds with an interest rate of 6.10%, based on forward 30-year Treasury rates and adding a spread of 160 basis points which is the current indicative spread for 30-year DTE Gas debt.<sup>1242</sup>

The Attorney General used the same cost rate determined by DTE.<sup>1243</sup>

Staff recommends a long-term cost rate of 4.38%, stating that the difference in the long-term debt rate recommendations from DTE and Staff are due to projected interest rates on the bonds to be issued in 2024 and 2025.<sup>1244</sup> Mr. Ufolla states that DTE projects an interest rate of 6.10% for both future issuances, with DTE's figures being derived from

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<sup>1239</sup> 4 Tr 2202; Ex. A-14, Sch. D2.

<sup>1240</sup> Id.

<sup>1241</sup> Id.

<sup>1242</sup> 4 Tr 2202-2203.

<sup>1243</sup> 4 Tr 1492.

<sup>1244</sup> 4 Tr 1618.

a projected treasury rate of 4.50% plus a historical 160 basis point spread, while Staff's figures of 5.70% and 5.31% for the 2024 and 2025 issuances, respectively, are calculated by utilizing projected treasury rates of 4.10% and 3.71% for 2024 and 2025 from IHS Markit and applying the same 160 basis point spread.<sup>1245</sup> He states that Staff's figures are simply an update to DTE's figures using more recent projections.<sup>1246</sup>

In rebuttal, Mr. Lepczyk states that based upon the rate curve as of May 15, 2024, DTE now calculates a Long-Term Debt issuance rate of 6.03% for 2024 based on an average projected 30-year treasury rate of 4.43% plus a 160 bps spread and 6.01% for 2025 based on an average projected 30-year treasury rate of 4.41% plus a 160 bps spread.<sup>1247</sup> With these updated projected issuances, the weighted average long-term debt cost as of September 30, 2025, approximates the projected long-term debt rate of 4.44%.

This PFD finds that DTE's projected long-term debt rate of 4.44%, which was confirmed with updated rate projections, should be adopted.

### **Short-Term Debt Cost Rate**

DTE forecasted a short-term debt cost rate of 5.95%.<sup>1248</sup> The Attorney General used the same short-term cost rate determined by DTE.<sup>1249</sup>

Staff projects a short-term debt cost rate of 4.46%.<sup>1250</sup> Mr. Ufolla states that the difference in the Short-Term Debt rate recommendations from DTE and Staff are due to projected Short-Term Overnight Financing (SOFR) rates in 2024 and 2025.<sup>1251</sup> Mr. Ufolla

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<sup>1245</sup> Id., Ex. S-4, Sch. D-2. Citation omitted.

<sup>1246</sup> Id.

<sup>1247</sup> 4 Tr 2210.

<sup>1248</sup> 4 Tr 2204; Ex. A-14, Sch.D3.

<sup>1249</sup> 4 Tr 1492.

<sup>1250</sup> 4 Tr 1617.

<sup>1251</sup> 4 Tr 1619.

states that DTE projects a short-term index rate of 5.38% and adds a 20 basis point historical spread plus 37 basis points in credit fees.<sup>1252</sup> He adds that, similar to the adjustment Staff made to Long-Term Debt rate, Staff simply updates the base rate of DTE's model using a projected SOFR of approximately 3.90% from IHS Markit weighted to correlate with the test year.<sup>1253</sup> He states that applying DTE's 20 basis point spread and credit fees resulted in a total cost rate of 4.46%, adding that Staff's figures are simply an update to DTE's figures using more recent projections.<sup>1254</sup>

In rebuttal, Mr. Lepczyk asserts that the actual short-term cost of debt is a more appropriate metric.<sup>1255</sup> He states that the actual year-to-date (through May) 2024 average 1-month short-term index has been 5.32%, and that adding the spread of 20 bps to the index of 5.32% brings the interest rate on short-term borrowings to 5.52%.<sup>1256</sup> He asserts that the cost of credit facility fees adds an incremental 0.37% to the cost of short-term debt for a total short-term debt rate of 5.89%.<sup>1257</sup> He argues that due to the uncertainty regarding the occurrence (and timing) of prospective Fed rate cuts, DTE feels it is prudent to use the 2024 actual average short-term rate of 5.89%.<sup>1258</sup>

This PFD finds that DTE's projected short-term debt rate of 5.89%, which was calculated using updated rate projections, should be adopted.

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<sup>1252</sup> Id.

<sup>1253</sup> 4 Tr 1619, Ex. S-4, Sch. D-3. Citation omitted.

<sup>1254</sup> Id.

<sup>1255</sup> 4 Tr 2211.

<sup>1256</sup> Id.

<sup>1257</sup> Id.

<sup>1258</sup> Id.

### **Overall Rate of Return**

Based on the foregoing discussion, this PFD recommends that the Commission adopt the capital structure, common equity balance, costs balances and rates recommended herein, resulting in an estimated overall weighted cost of total capital as shown in Appendix D to this PFD.)

## **VI.**

### **ADJUSTED NET OPERATING INCOME**

Adjusted Net Operating Income (NOI) represents the difference between the company's projected test year operating revenues and expenses. The first step in computing a company's NOI is to forecast its overall sales level, and then convert that figure into the appropriate amount of expected revenue to be received during the test year through application of the utility's proposed rates, adjusted for revenue received by other utility operations. The second step is to determine the expenses that are expected to be incurred during the test year, and then subtract that amount from overall revenues.

### **Throughput**

DTE states that Throughput represents the total gas sales and transportation volumes delivered to end-use customers during the test period.<sup>1259</sup> DTE projects 1,340,341 sales customers, 545 EUT customers, sales volumes of 159.1 billion cubic feet (Bcf), and transportation volumes of 150.7 Bcf.<sup>1260</sup>

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<sup>1259</sup> DTE initial brief, p. 80.

<sup>1260</sup> Id.; Ex. A-15, Sch. E1, E6, E7.

## **Sales Forecast**

Mr. Chapel states that DTE Gas's unadjusted total 2022 sales were 164.6 Bcf.<sup>1261</sup> He adds that for this forecast, he used a 15-year weather normalization methodology, calculated from 2008-2022 to calculate an adjustment for the 2022 colder weather, with actual 2022 total sales volumes were decreased by 1.8 Bcf to arrive at weather normalized total sales of 162.7 Bcf.<sup>1262</sup>

Mr. Chapel states that the forecasted 2023 normalized actual sales total 160.9 Bcf, with actual and forecasted 2023 total sales volumes of 151.1 Bcf were increased by 9.8 Bcf to arrive at weather normalized total sales.<sup>1263</sup>

Mr. Chapel states that the January 2024 to September 2024 transitional period forecasted sales total is 109.7 Bcf, and the October 2024 to September 2025 projected test year forecasted sales total is 159.1 Bcf.<sup>1264</sup>

Mr. Chapel states that the October 2024 to September 2025 projected test year forecasted sales total is 159.1 Bcf and that these volumes are forecasted using the 15-year weather normalization methodology from 2008-2022.<sup>1265</sup>

Mr. Chapel states that weather normalization adjusts actual consumption from a past period to compensate for the impact of warmer-than-normal or colder-than-normal weather temperatures (measured in Heating Degree Days, a measure of how temperature relates to natural gas usage for heating purposes) that occurred during that time.<sup>1266</sup> He adds that DTE Gas is presenting normal HDDs based upon 15-year normal

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<sup>1261</sup> 2 Tr 205; Ex. A-15, Sch. E1.

<sup>1262</sup> *Id.*

<sup>1263</sup> 2 Tr 205-206; Ex. A-15, Sch. E1.

<sup>1264</sup> 2 Tr 206; Ex. A-15, Sch. E1.

<sup>1265</sup> *Id.*

<sup>1266</sup> 2 Tr 206.

weather calculated from calendar year 2008 through calendar year 2022, noting that in Case No. U-15985, the Commission approved 15-year normal weather based upon 1994-2008 and that in each of DTE Gas' filed rate cases since then, the Commission has continued to approve the average of the most recent 15 calendar years at the time of filing as "normal weather" in that case.<sup>1267</sup>

Mr. Chapel states there are five key elements used in projecting volumes in the residential sales market; a) the expectation of normal weather HDDs by region, b) the forecast of the number of customers, by month, in the even different market areas that DTE Gas serves, c) an analysis of the usage per customer per HDD at varying temperatures, d) DTE's Energy Waste Reduction (EWR) program, and e) expected changes, if any, in DTE's system-weighted heating value in Btu/cf.<sup>1268</sup>

Mr. Chapel states that the number of DTE Gas's residential heating customers peaked in 2006 at a level of 1,158,586 customers, customer count then declined by over 57,000 through 2012, to 1,101,255, and since that time, residential customers have grown to a total of 1,201,131 as of 2022.<sup>1269</sup> He adds that annual net total customer growth through 2028 is projected to be approximately 8,200 to 8,700 annually.<sup>1270</sup>

Mr. Chapel states that over the past two years, normalized consumption per residential customer rebounded almost to pre-CoVid-19 levels.<sup>1271</sup> He adds that only in the past two years, as economic conditions due to CoVid-19 have improved, normalized

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<sup>1267</sup> 2 Tr 208; Ex. A-15, sch. E5.

<sup>1268</sup> 2 Tr 214-215.

<sup>1269</sup> 2 Tr 217.

<sup>1270</sup> *Id.*

<sup>1271</sup> 2 Tr 218.

residential consumption has increased to 93.0 Mcf/customer as of August 2023 – higher than the two CoVid-19 years, but not quite as high as the preCoVid-19 levels.<sup>1272</sup>

Mr. Chapel states forecasting sales in the commercial market involves forecasting the number of customers, the 2008-2022 15-year weather normalized usage per customer for the forecast period, and further changes due to the EWR program and heating values.<sup>1273</sup> He adds that in 2014, DTE Gas began to add commercial GS22 customers, with this growth continuing through calendar year 2022 and being expected to grow through 2028.<sup>1274</sup>

Mr. Chapel states that from the 12-months ended August 2020, the commercial GS-1 space heat class saw a significant drop in normalized demand down to 414.2 Mcf/customer, with normalized demand dropping during 12-months ended August 2021 to 404.5 Mcf/customer.<sup>1275</sup> Customer behavior in the GS-1 class, largely small commercial in nature, was highly affected by CoVid-19. He adds that for 12-months ended August 2022 and 2023, normalized demand in this class of customer rebounded strongly to 428.4 Mcf/customer and 427.7 Mcf/customer, respectively.<sup>1276</sup>

Mr. Chapel states DTE Gas's rate schedule industrial classes have remained relatively small and unchanged, with the majority of DTE Gas's larger industrial customers take End-User Transportation (EUT) service from DTE Gas.<sup>1277</sup> He states that DTE Gas is forecasting industrial sales volumes to be approximately 1.0 Bcf in 2024, decreasing

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<sup>1272</sup> Id.

<sup>1273</sup> 2 Tr 223.

<sup>1274</sup> Id.; Ex. A-15, Sch. E3.

<sup>1275</sup> 2 Tr 224; Ex. A-15, Sch. E4.

<sup>1276</sup> 2 Tr 225.

<sup>1277</sup> 2 Tr 226.

slightly to 0.9 Bcf per year for rate schedule sales to industrial customers through 2028.<sup>1278</sup>

DTE supports revenue for the historical test year totaling \$1,242.5 million including reclassifications and adjustments.<sup>1279</sup> Ms. Uzenski states that total operating revenue is expected to decrease by \$13.1 million to \$1,229,365,000.<sup>1280</sup>

Staff's total projected operating revenue for the test year ending September 30, 2025, is \$1,189,887,000, which is a \$39,478,000 decrease from DTE's projected operating revenue.<sup>1281</sup> Ms. Todd states that the total projected operating revenue consists of the projected revenue from gas sales customers, end-use transportation customers (EUT), Exelon, off-system transportation and storage, and other operating revenue.<sup>1282</sup> Staff asserts that the difference between DTE's and Staff's projections is related to sales revenue and is due to Staff's average cost of gas adjustment which impacts both the cost of gas sold (COGS) and has an equal offsetting reduction to sales revenue.<sup>1283</sup> Ms. Royal recommends an October 2024 through September 2025 jurisdictional average cost of natural gas of \$4.1015/Mcf, which is a \$0.2797/Mcf decrease from the \$4.3812/Mcf, that DTE proposed for the 12-month period.<sup>1284</sup> She adds that DTE Gas updated the monthly costs and volumes of natural gas in its underground storage reservoirs by incorporating the actuals from January through 21 December 2023, and updated the projected monthly costs and volumes from January 2024 through December 2025 using a five-day New

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<sup>1278</sup> Id.; Ex. A-15, Sch. E2.

<sup>1279</sup> 4 Tr 2310; Ex. A-13, Sch. C3.

<sup>1280</sup> Id.

<sup>1281</sup> 4 Tr 1638-1639; Ex. S-3.0, Sch. C3.

<sup>1282</sup> 4 Tr 1639.

<sup>1283</sup> Staff initial brief, p. 28.

<sup>1284</sup> Id., p. 29.

York Mercantile Exchange (NYMEX) settlement average from February 12-16, 2024.<sup>1285</sup> Ms. Royal states that a) the September 2024 through September 2025 average cost of natural gas in underground storage reservoirs for GCR customers decreased by \$9,133,000 to \$47,428,000; b) the September 2024 through September 2025 average volume of natural gas in underground storage reservoirs decreased by 4,826,000 thousand cubic feet (Mcf) to 34,255,000 Mcf; c) the September 2024 through September 2025 average ending balance for gas customer choice (GCC) deferred asset of natural gas in underground storage reservoirs decreased by \$2,879,000 to \$39,161,000; and d) the September 2024 through September 2025 average volume of natural gas in underground storage reservoirs decreased by 460,000 Mcf to 3,589,000 Mcf.<sup>1286</sup> Staff adds that neither DTE nor any intervenors have rebutted Staff's recommendation.<sup>1287</sup>

As such, this PFD recommends that the Commission adopts Staff's recommended disallowance of \$39,478,000.

Mr. Coppola states that after reviewing the sales forecast, he determined that DTE has significantly underestimated the gas sales volume for residential and commercial customers and the related test year revenue.<sup>1288</sup>

Mr. Coppola states that he calculated the average weather-normalized annual gas usage per customer for each of the customer classes, which results show that from 2018 to 2023, the average annual gas usage per residential customer (Rate A) declined from 95.67 Mcf to 92.62 Mcf, or an average of 0.6% annually.<sup>1289</sup> He adds that in contrast, DTE

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<sup>1285</sup> 4 Tr 1807-1808; Ex. S-11.1, S-11.2.

<sup>1286</sup> 4 Tr 1810.; Ex. S-11.2.

<sup>1287</sup> Staff initial brief, p. 8.

<sup>1288</sup> 4 Tr 1514.

<sup>1289</sup> Id.

has projected a decline in gas usage of 1.0% in 2024 with an additional decline of 1.6% in 2025 for a cumulative decline of 2.3% between 2023 and the projected test year.<sup>1290</sup> He states that DTE's projected test year sales forecast results in average annual gas usage per residential customer of 90.52 Mcf, which is the lowest level since at least 2018.<sup>1291</sup>

Mr. Coppola states that for commercial customers (Rate GS-1), the analysis shows that the average usage per customer decreased between 2018 and 2023 from 461.91 Mcf to 446.37 Mcf, while over this period, the average annual decrease in usage per customer was 0.7%.<sup>1292</sup> He adds, however, that DTE's sales forecast shows the average usage per customer declining 2.0% in 2024 from 2023, with a further decrease of 1.6% in 2025, for a cumulative decline of 3.3% from 2023 to the end of the projected test year, which decline comes despite DTE forecasting an increase of approximately 462 commercial sales customers from 2023 to 2025.<sup>1293</sup> He states that although the EWR program pursued by DTE will have some impact on customer usage, the forecasted increase in the number of residential and commercial customers should be a mitigating factor against the loss of sales from the 1% targeted reduction in energy conservation.<sup>1294</sup> He adds that the decline in Rate A residential and Rate GS-1 commercial sales between 2023 and the projected test year is significant, highly unusual, and unsupported.<sup>1295</sup>

Mr. Coppola asserts that DTE does not explain these changes in customer usage, noting that Mr. Chapel does not analyze, explain, or support changes in gas volumes

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<sup>1290</sup> 4 Tr 1514-1515; Ex. AG-32.

<sup>1291</sup> 4 Tr 1515.

<sup>1292</sup> *Id.*; Ex. AG-32.

<sup>1293</sup> *Id.*

<sup>1294</sup> *Id.*

<sup>1295</sup> *Id.*

usage between historical and forecasted periods by rate schedule or customer class.<sup>1296</sup>

He adds that DTE forecasted EWR lost sales at approximately 1% of recent historical sales, which rate of decline he asserts appears to be overly optimistic, given that over the five-year period from 2018 to 2028 the average annual gas usage for residential customers has decline by only 0.6%, or about half the EWR assumed rate of reduction.<sup>1297</sup>

Mr. Coppola states that the historical gas usage period selected by DTE to forecast future gas sales is concerning.<sup>1298</sup> Noting that DTE used two years of historical gas usage from August 2021 to July 2023 to develop the average customer historical gas usage factors, Mr. Coppola states that there are two events that impacted customer usage during this period, which negatively affected customer gas usage: the lingering effect of the Covid-19 pandemic continued into 2021 and likely continued to depress customer gas usage during the August to December 2021 period and potentially subsequent months into early 2022, and second, in 2022 gas prices spiked considerably, more than doubling from prior years, which large increase in gas bills forces customers to undertake added energy conservation steps, at least temporarily, until gas prices subside, which occurred beginning in early 2023.<sup>1299</sup> He states that DTE provided information shows the significant decline in gas usage per customers with the start of Covid-19 in early 2020 and the partial bounce back in early 2022 before a further decline in 2022 and early 2023.<sup>1300</sup> He asserts that the Commission should not rely on DTE's forecasted sales volumes for Rate A residential and GS-1 commercial sales, with a better approach being to use the latest

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<sup>1296</sup> 4 Tr 1516.

<sup>1297</sup> *Id.*

<sup>1298</sup> 4 Tr 1517.

<sup>1299</sup> *Id.*

<sup>1300</sup> 4 Tr 1518.

year of actual gas sales and apply the actual five-year percentage decline trend that represents the net effect of sales losses from EWR and sales increases from customer additions and other changes in customer gas usage over a longer time period than two years.<sup>1301</sup>

Mr. Coppola calculated revised residential and commercial sales and related distribution revenue adjustments based on his analysis.<sup>1302</sup> He forecasted Rate A residential sales of 113,767 MMcf for the projected test year, which is an increase of 1,303 MMcf over DTE's forecast, and based on the current distribution rate billed to residential customers, the additional sales result in incremental revenue of \$5,063,000 for the projected test year.<sup>1303</sup> He adds that for Rate GS-1 commercial sales, he forecasted higher sales of 848 MMcf for the projected test year for additional distribution sales revenue of \$3,227,000.<sup>1304</sup> He concludes that in total, the incremental forecasted revenue for the projected test year is \$8,290,000.<sup>1305</sup>

Mr. Chapel counters that the period that Mr. Coppola chose - a period that begins before the Covid pandemic, spans the Covid pandemic, and concludes after the Covid pandemic - is problematic, as the Covid pandemic had a significant impact on consumption per customer.<sup>1306</sup> He states that Ex. AG-33 shows a marked dip in consumption per customer is evident for the two pandemic years of 12 months ended August 2020 and 12 months ended August 2021.<sup>1307</sup> He adds that time period Mr.

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<sup>1301</sup> 4 Tr 1518.

<sup>1302</sup> 4 Tr 1518-1519

<sup>1303</sup> 4 Tr 1519.

<sup>1304</sup> *Id.*

<sup>1305</sup> *Id.*

<sup>1306</sup> 2 Tr 231.

<sup>1307</sup> *Id.*

Coppola chose is completely arbitrary, unlike DTE which he asserts has used a consistent method for each regulatory filing it has made over the past 15 years whereby DTE considers only the most recent 24 months of customer consumption and makes standard and consistent adjustments to that customer behavior in compiling its forecast.<sup>1308</sup> He states that Mr. Coppola's analysis is inconsistent, asserting that the number of customers that DTE may add or lose over a forecast period should have no impact on the assumptions around consumption per customer.<sup>1309</sup> Regarding Mr. Coppola's assertion that the 1% EWR loss rate does not appear realistic, DTE counters that the 1% EWR decline rate was approved by the Commission in DTE's most recent EWR filing, Case No. U-21322.<sup>1310</sup>

MNSC asserts that on average, DTE's sales per customer have declined about 30 percent over the 26- year period from 1997 to 2022.<sup>1311</sup> Dr. Hopkins states that DTE projects continuing declines in gas usage per customer.<sup>1312</sup> He asserts that DTE's gas demand forecast does not fully reflect potential future changes in gas demand and therefore is likely to be too high, mainly because DTE's load forecasting methodology heavily relies on historical trends and does not recognize any climate policy impacts that are likely to arise over the next decade (except small impacts from the continuation of the existing EWR programs).<sup>1313</sup> He adds that DTE development forecasts of Proactive conversions based on "historical attachment data and current market trends that identifies[sic] the cost differential between propane and natural gas" is inadequate to fully

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<sup>1308</sup> 2 Tr 232.

<sup>1309</sup> 2 Tr 232-233.

<sup>1310</sup> 2 Tr 233.

<sup>1311</sup> 4 Tr 849. Citation omitted.

<sup>1312</sup> Id.

<sup>1313</sup> 4 Tr 850.

capture the current market trend, because adoption of electric heating has been increasing considerably over the past several years.<sup>1314</sup> He states that DTE acknowledges that it does not incorporate the impacts of the state's climate and clean energy laws into its customer count forecast.<sup>1315</sup>

Mr. Chapel counters that DTE's load forecasting methodology examines customer behavior over a very recent period of time: 24- 24 months ending July.<sup>1316</sup> He adds that DTE's methodology is reflective of recent customer behavior, adjusted for factors such as EWR and heating value, and provides a reasonable expectation of what normal customer demand will be in the October 2024 to September 2025 projected Test Year.<sup>1317</sup> He asserts that Dr. Hopkins does not offer an alternative and quantifiable demand forecast for the October 2024 to September 2025 projected Test Year.<sup>1318</sup>

This PFD agrees with the Attorney General and MNSC, finding that DTE has significantly underestimated the gas sales volume for residential and commercial customers and the related test year revenue. This PFD further finds that the Attorney General has adequately supported her assertion that the incremental forecasted revenue for the projected test year is \$8,290,000. Thus, this PFD recommends that the Commission adopt the Attorney General's forecasted revenue projection.

### **Weather Normalization**

Mr. Chapel states that weather normalization adjusts actual consumption from a past period to compensate for the impact of warmer-than-normal or colder-than-normal

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<sup>1314</sup> 4 Tr 851.

<sup>1315</sup> 4 Tr 853; Ex. MEC-10.

<sup>1316</sup> 2 Tr 236.

<sup>1317</sup> 2 Tr 237.

<sup>1318</sup> 2 Tr 237-238.

weather temperatures (measured in Heating Degree Days) that occurred during that time.<sup>1319</sup> He asserts that for this case, DTE Gas is presenting normal HDDs based upon 15-year normal weather calculated from calendar year 2008 through calendar year 2022, noting that in Case No. U-15985, the Commission approved 15-year normal weather based upon 1994- 2008.<sup>1320</sup> DTE asserts that no party challenges the methodology or the need to adjust for weather normalization.<sup>1321</sup>

### **Customer Usage Forecast**

Mr. Chapel states rate schedule volumes are projected by taking the weather normalized 2022 rate schedule volumes and adjusting them to reflect expected volume changes.<sup>1322</sup> He adds that there are three main issues that are expected to affect sales volumes into the projected Test Year of October 2024 – September 2025; a) DTE Gas experienced changes in the number of customers it served through 2023 and expects this to continue into 2024 and 2025; b) DTE Gas expects changes in overall rate schedule consumption per customer due to variances in DTE's gas heating value, demographic changes in DTE's customer base, DTE's Energy Waste Reduction (EWR) program on an ongoing basis through 2023 and into the projected test year, and customer behavior in response to weather as reflected in the most recent 24 months; and c) assuming 15-year normal weather for the forecast will capture weather-related effects impacting customers' usage on a weather normal basis.<sup>1323</sup>

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<sup>1319</sup> 2 Tr 207.

<sup>1320</sup> 2 Tr 208.

<sup>1321</sup> DTE initial brief, p. 84.

<sup>1322</sup> 2 Tr 208.

<sup>1323</sup> 2 Tr 208-209.

Mr. Chapel states that the normal rate schedule forecast volumes for the projected Test Year are 159.1 Bcf.<sup>1324</sup> He adds that for 2023, DTE Gas observed volumetric changes from the weather-normalized 2022 Base Year, such that DTE expects 1) a reduction in normalized sales of 2.4 Bcf due largely to the effects of DTE's EWR program and an expected increase in DTE's system-wide heating value, and 2) an increase in normalized sales of 0.5 Bcf due to incremental customer attachments in 2023, with these adjustments resulting in a normal weather forecast of 160.9 Bcf for 2023.<sup>1325</sup> He states that for the transitional January 2024 to September 2024 period, DTE Gas forecasts volumetric changes from weather-normalized 2023, resulting in a normal weather forecast of 109.7 Bcf for January 2024 to September 2024.<sup>1326</sup>

Mr. Chapel states that for the October 2024 to September 2025 Test Year, DTE Gas forecasts volumetric changes from the weather normal transitional January 2024 to September 2024 period, with DTE expecting 1) an increase in normalized sales of 46.9 Bcf due to the fact that there are an additional three months in the Test Year, offset by DTE's EWR program, and 2) an increase in cumulative normalized sales of 2.5 Bcf due to incremental customer attachments over the course of the Test Year.<sup>1327</sup> He adds that these adjustments result in a normal weather forecast of 159.1 Bcf for the Test Year, with the change from the weather-normalized total sales of 162.7 Bcf in the historical period to 159.1 Bcf 22 in the projected year.<sup>1328</sup>

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<sup>1324</sup> 2 Tr 209; Ex. A-15, Sch. E1.

<sup>1325</sup> Id.

<sup>1326</sup> 2 Tr 210.

<sup>1327</sup> Id.

<sup>1328</sup> Id.; Ex. A-15, Sch. E1, Sch. E2.

Mr. Chapel states that the heating value for the most recent 12-months was 1,054 Btu/Mcf, such that DTE assumes that value to be the implicit heating value for all forecast years in this case.<sup>1329</sup>

Mr. Coppola asserts that for EWR lost sales, which DTE forecasted at approximately 1% of recent historical sales, this rate of decline appears to be overly optimistic, given that over the five-year period from 2018 to 2028 the average annual gas usage for residential customers has decline by only 0.6%, or about half the EWR assumed rate of reduction.<sup>1330</sup>

Mr. Chapel counters that the 1% EWR decline rate was approved by the Commission in DTE's most recent EWR filing, Case No. U-21322.<sup>1331</sup> He adds that analysis of the most recent 12-months GCR/GCC sales ended April 2024 indicate that, on a normalized basis, consumption per customer is trending downward by a rate that, at this point, exceeds the Company's 1% EWR assumption.<sup>1332</sup>

Dr. Hopkins asserts that the recent historical trend in heat pump and gas heating adoption rates is not consistent with the way DTE is forecasting the number of gas customers for new construction (or routine growth), where it is assuming a fixed share of 78% gas customers among all residential new construction projects.<sup>1333</sup> DTE counters that Dr. Hopkins is relying on nationwide data not specific to Michigan and that many states have dramatically different heating demands and behaviors than Michigan.<sup>1334</sup>

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<sup>1329</sup> 2 Tr 213.

<sup>1330</sup> 4 Tr 1516.

<sup>1331</sup> 4 Tr 233.

<sup>1332</sup> 2 Tr 234; Ex. A-28, Sch. R1.

<sup>1333</sup> 4 Tr 853.

<sup>1334</sup> DTE initial brief, p. 86.

### **Exelon Energy Company**

Mr. Chapel states that Exelon customers (formerly served by DTE Gas) are removed from the sales forecasts because they receive all of their gas services from Exelon instead of DTE Gas.<sup>1335</sup>

Ms. Todd states that Staff mostly agrees with DTE's treatment of Exelon in this case, noting that DTE properly excluded the difference between revenues and costs from rate design for other classes, which ensures that no other customers pay for this difference consistent with the Commission's prior determinations.<sup>1336</sup> She adds that, unlike DTE, Staff appropriately made the proposed revenue for Exelon equal to the amount reported in Staff's COSS.<sup>1337</sup>

This PFD agrees with Staff and recommends that the Commission approve Staff's treatment of the Exelon easement.

### **Cost of Gas Forecast**

Mr. Chapel states that for the October 2024 – September 2025 projected Test Year, he project a \$4.3812 per Mcf jurisdictional cost of gas.<sup>1338</sup> He adds that he derived his cost of gas projection based on New York Mercantile Exchange (NYMEX) close prices for natural gas futures contracts on September 22, 2023.<sup>1339</sup>

Ms. Royal states that due to the timing of the case, Staff requested DTE Gas utilize more recent data than DTE had available to update the test year's jurisdictional average cost of natural gas than when the case was prepared, and thus that DTE updated the

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<sup>1335</sup> 2 Tr 227.

<sup>1336</sup> 4 Tr 1642.

<sup>1337</sup> Id.

<sup>1338</sup> 2 Tr 228.

<sup>1339</sup> Id.

volumes and costs of both DTE Gas' fixed and floating supply, the transportation costs, and used a five-day average of NYMEX settlement prices of natural gas contracts from February 12 through 16, 2024, to project the costs of the natural gas futures contracts for October 2024 through September 2025.<sup>1340</sup> She adds that for the October 2024 through September 2025 jurisdictional average cost of natural gas, Staff calculates a jurisdictional average cost of natural gas of \$4.1015/Mcf, which is a decrease of \$0.2797/Mcf from the test period jurisdictional average cost of natural gas that DTE proposed.<sup>1341</sup>

This PFD agrees with Staff and recommends that the Commission adopt Staff's updated cost of natural gas.

### **End-Use Transportation**

Mr. Decker states End-Use Transportation (EUT) customers are DTE Gas's largest Commercial and Industrial (C&I) customers, who purchase their natural gas from third-party gas suppliers and then contract with DTE Gas to transport and balance the customers' nominated gas supplies on the DTE Gas system for delivery to the customers' facilities.<sup>1342</sup> He adds that DTE Gas's Rate Book includes four EUT rate schedules: ST (Small Transportation), LT (Large Transportation), XLT (Extra Large Transportation), and XXLTL (Extra-Extra Large Transportation).<sup>1343</sup>

Mr. Decker states that one of the DTE Gas EUT customers had Commission approved Special Contracts during the 2022 historic test year, and that DTE expects to have one Special Contract customer during the future test year.<sup>1344</sup> He adds that DTE is

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<sup>1340</sup> 4 Tr 1811; Ex. S-11.3, S-11.4.

<sup>1341</sup> 4 Tr 1812-1813; ex. S-11.4.

<sup>1342</sup> 2 Tr 42.

<sup>1343</sup> Id.

<sup>1344</sup> 2 Tr 45; Ex. A-15, Sch. E6.

not seeking recovery of the discounted transportation rates provided in the Special Contract and thus it is included in the customer count XXLT cost base rate volumes for the projected test year.<sup>1345</sup>

Mr. Decker states that during the historical test year, DTE Gas had 539 EUT customers, and that DTE Gas projects it will have 545 EUT customers during the projected test year.<sup>1346</sup> He adds that During the historical test year, EUT customers transported 146.6 Bcf. DTE Gas is projecting EUT customers will transport 150.7 Bcf during the projected test year.<sup>1347</sup> He states that the main drivers that influence the volumes of gas transported by DTE's power generation customers are: 1) summer temperatures, 2) natural gas prices, 3) power plant outages, 4) new power generation customers added to EUT space, and 5) other power generation customers ceasing operations.<sup>1348</sup> He asserts that the historical test year alone does not provide a reasonable forecast for the power generation volumes due to the significant year to year variation in the five factors.<sup>1349</sup> He adds that DTE utilized the most recent five-year period available at the time forecasts were prepared for this rate case, which started September 2018 and ended August 2023, for most of its power generation customer projections.<sup>1350</sup> He states that the five-year average power generation annual volumes ending August 2023 is 61.5 Bcf.<sup>1351</sup> He adds that the Commission found that the five-year historical period best represents DTE's projected power generation gas use in Case Nos. U-18999 and U-

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<sup>1345</sup> Id.

<sup>1346</sup> 2 Tr 46; Ex. A-15, Sch. E6.

<sup>1347</sup> Id.; Ex. A-15, Sch. E7.

<sup>1348</sup> 2 Tr 48.

<sup>1349</sup> Id.

<sup>1350</sup> 2 Tr 48-49.

<sup>1351</sup> 2 Tr 49, Table 2.

20940, and that DTE utilized the five-year historical period for power generation volumes in settled Case No. U-20642.<sup>1352</sup>

Mr. Decker states that DTE's EUT distribution, monthly customer charge, standby charges, and minimum commitment revenues for 2022 were \$121.9 million, and that DTE's projected EUT Revenue is \$122.8 million (at current rates), consisting primarily of distribution, monthly customer charge, and standby charge revenues.<sup>1353</sup>

Mr. Coppola states that DTE indicated that the latest twelve months of gas deliveries as of March 2024 to power generation customers shows that gas deliveries to this customer segment continued to increase since the twelve months ended August 2023 volumes of 64.1 Bcf. and that the gas deliveries to power generation customers for the twelve months ended March 2024 were 72.4 Bcf.<sup>1354</sup> He adds that he calculated an updated five-year average of gas deliveries of 64.1 Bcf., which updated volume is 2.6 Bcf higher than the 61.5 Bcf previously calculated by DTE and included in the EUT gas delivery forecast for the projected test year.<sup>1355</sup> Thus, he recommends that the Commission adopt this adjustment to increase end-user transportation volumes by 2.6 Bcf for transportation Rate XXLT.<sup>1356</sup>

Mr. Chapel counters that in DTE's last general rate case (Case No. U-20940), the Commission agreed with the as-filed five-year average methodology used for the power generation customer future test year volumes and did not find it necessary to change the forecasting methodology from the long-standing precedent.<sup>1357</sup> He adds that using the

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<sup>1352</sup> 2 Tr 50.

<sup>1353</sup> 2 Tr 52; Ex. A-13, Sch. C3.2.

<sup>1354</sup> 4 Tr 1520; Ex. AG-61.

<sup>1355</sup> *Id.*

<sup>1356</sup> *Id.*

<sup>1357</sup> 2 Tr 120-121.

same five-year average approach whereby DTE utilizes the latest volumes available upon the filing of the rate case provides the most consistent approach to forecasting this subset of EUT customers.<sup>1358</sup>

This PFD agrees with the Attorney General, finding that her updated five-year average of gas deliveries should be used, as that average is based on the most recent historical information. DTE is misleading by attempting to rely on the Commission's prior order in case No. U-20940; in that case, the issue was whether a five-year or a three-year average was preferred, not as DTE implies here whether an "as-filed" five-year average is preferred over a five-year average using the latest information.<sup>1359</sup>

### **EUT Transportation Rates**

### **Monthly Customer Charges**

Mr. Decker states that DTE Gas is proposing that the monthly customer charge for Rate A be changed to \$17.60, and to maintain historical consistency, DTE Gas proposes that the monthly customer charge for Rate 2A-Meter Class I be set identical to residential Rate A at \$17.60 and the monthly customer charge for Rate 2A-Meter Class II and Rate GS-1 be set at \$50.00.<sup>1360</sup> He adds that the proposed Rate GS-2 monthly customer charge is \$925, the proposed Rate S monthly customer charge is \$275 and the monthly customer charges for EUT Rates ST, LT, XLT, and XXLT are \$3,300, \$9,100, \$20,000 and \$230,000, respectively.<sup>1361</sup>

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<sup>1358</sup> 2 Tr 121.

<sup>1359</sup> See, Case No. U-20940, Order, December 9, 2021, p. 108.

<sup>1360</sup> 2 Tr 99; Ex. A-16, Sch. F2.

<sup>1361</sup> Id.

### **EUT Cost Based Rates and Minimum and Maximum Optional Rates**

Mr. Decker states that he is proposing that the minimum optional rate under rate schedules ST and LT remain at \$0.23 per Mcf and the minimum optional rate under rate schedule XLT and XXLT remain at \$0.18 per Mcf and \$0.05 per Mcf, respectively.<sup>1362</sup> He adds that consistent with the Commission orders in Case Nos. U-15985, the U-16999 settlement, U-17999, U-18999, U-20940 and utilized in the U-20642 settlement, he recommends setting the maximum rate for rate schedule XXLT equal to the rate calculated for rate schedule XLT.<sup>1363</sup>

Mr. Coppola states that DTE's forecast of total transportation volume of 150.7 Bcf for the projected test year represents an increase of 4.1 Bcf, or 2.8%, from the actual transportation volumes billed in 2022, with the increase being mostly due to higher deliveries to power generation plants since 2022.<sup>1364</sup> He adds that while DTE calculates an average volume of 61.5 Bcf for annual deliveries to power generation customers during the past five years, DTE shows that gas deliveries to this customer segment continued to increase since the twelve months ended August 2023 volumes of 64.1 Bcf.<sup>1365</sup> He states that the gas deliveries to power generation customers for the twelve months ended March 2024 were 72.4 Bcf., with which he calculated an updated five-year average of gas deliveries of 64.1 Bcf.<sup>1366</sup> Thus, he recommend that the Commission adopt this adjustment to increase end-user transportation volumes by 2.6 Bcf for transportation Rate XXLT.<sup>1367</sup>

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<sup>1362</sup> 2 Tr 101; Ex. A-16, Sch. F2.

<sup>1363</sup> 2 Tr 102.

<sup>1364</sup> 4 Tr 1519; Ex. A-15, Sch. E7.

<sup>1365</sup> 4 Tr 1520; Ex. AG-35.

<sup>1366</sup> Id.

<sup>1367</sup> Id.

Mr. Coppola states that the current volumetric rate for Rate schedule XXLTL is \$0.1933 per Mcf.62, with which he calculated additional revenue of \$503,000.<sup>1368</sup> Thus, he recommends that the Commission increase DTE's forecasted end-user transportation revenue by this amount.<sup>1369</sup>

Dr. Hopkins states that DTE projects total customer counts based on DTE's projections of customer attachments (from new properties) and customer non-attachments (from the existing properties that are currently receiving gas services from DTE), with a steady increase in customers over the next five years at annual growth rates of 0.7 percent for residential heating customers and 0.3 percent for commercial heating customers.<sup>1370</sup> He adds that DTE is using recent historical data to project growth in non-attachment customers and assumes no impacts from future policy changes.<sup>1371</sup>

Dr. Hopkins states that on average, DTE's sales per customer have declined about 30% over the 26- year period from 1997 to 2022, and that DTE projects continuing declines in gas usage per customer.<sup>1372</sup> He asserts that DTE's gas demand forecast does not fully reflect potential future changes in gas demand and therefore is likely to be too high, as DTE's load forecasting methodology heavily relies on historical trends and does not recognize any climate policy impacts that are likely to arise over the next decade (except small impacts from the continuation of the existing EWR programs).<sup>1373</sup>

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<sup>1368</sup> 4 Tr 1521

<sup>1369</sup> *Id.*

<sup>1370</sup> 4 Tr 846; Ex. A-15, Sch. E3.

<sup>1371</sup> 4 Tr 849.

<sup>1372</sup> *Id.* Citation omitted.

<sup>1373</sup> 4 Tr 850.

Dr. Hopkins notes that DTE states that it does not incorporate the impacts of the state's climate and clean energy laws into its customer count forecast.<sup>1374</sup> He adds that DTE further states that “[c]urrently, given the current legislation and costs”, DTE doesn’t “believe electrification will have a significant impact on natural gas consumption in the next ten years,” and that if it becomes significant in the future, DTE’s current methodology “would be adapted to include the impact.”<sup>1375</sup> He asserts that DTE’s assessment is inconsistent with both state decarbonization policies that require emissions reduction within the next 10 years and already existing trends towards residential electrification.<sup>1376</sup>

Dr. Hopkins states that a load forecast with high gas consumption is likely to lead to overbuilding of gas pipeline systems and would also prevent DTE from considering retirements of gas pipelines in some segments of its service territory where a majority of customers may leave the system (e.g., switch to electric heating) to choose cleaner heating options that are supported by state and federal policies.<sup>1377</sup> He asserts that overbuilding of gas pipeline systems driven by DTE’s flawed load forecast could result in overly expensive gas system costs and overly high gas bills for consumers.<sup>1378</sup>

In order to improve its load forecast, Dr. Hopkins states

I recommend that the Commission require DTE to develop a forecast of future sales that reflects policy and market developments. For example, the Healthy Climate Plan lays out a roadmap to 52 percent GHG reductions from 2005 baselines by 2030, including a 17 percent reduction in emissions related to heating Michigan buildings. The Commission should require DTE to incorporate this 17 percent reduction in emissions from space heating end uses when it develops a policy-consistent sales forecast. For a business-as-usual case, I recommend that DTE develop its forecasts of gas customer counts and gas usage based on updated market conditions, including the latest data on the share of heat pump

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<sup>1374</sup> 4 Tr 853. Citation omitted.

<sup>1375</sup> 4 Tr 854. Citation omitted.

<sup>1376</sup> *Id.*

<sup>1377</sup> *Id.*

<sup>1378</sup> *Id.*

and gas furnace sales and installations. DTE should also examine the impacts of the declining share of gas customers, driven by various policies, on its forecast of gas demand. The Commission should also order DTE to make all underlying data, models, and assumptions for its forecast publicly available so that stakeholders and Commission staff can review the Company's methods.<sup>1379</sup>

Dr. Hopkins adds that DTE should be required to evaluate all capital expenditures and supply contracts against both its business-as-usual forecast and a policy-consistent forecast.<sup>1380</sup>

### **Midstream Revenue**

Mr. Decker states that Midstream Services (Midstream) represent the sale of storage and transportation services to off-system customers, and that off-system refers to customers who transport gas from a receipt point into DTE's storage and transmission system to a delivery point that is interconnected to another local gas distribution company, or a pipeline not owned by DTE Gas.<sup>1381</sup> He adds that the forecasted Midstream revenue contribution for the projected test period is \$111.6 million.<sup>1382</sup> He states that Midstream revenues approved in Case No. U-20940 were \$102.8 million, such that DTE in this case is projecting Midstream revenues to be \$8.8 million more than DTE's last rate case.<sup>1383</sup>

Mr. Decker states that for the projected test period, there will be 62.5 Bcf of Company-owned storage capacity available for sale to off-system customers, the same as Case No. U-20940.<sup>1384</sup>

Mr. Decker states that total projected storage revenue included in the projected test period is \$38.5 million, which includes \$34.1 million Contract Storage and \$4.4 million

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<sup>1379</sup> 4 Tr 855.

<sup>1380</sup> Id.

<sup>1381</sup> 2 Tr 53.

<sup>1382</sup> 2 Tr 54-55, Table 3.

<sup>1383</sup> 2 Tr 54-55.

<sup>1384</sup> 2 Tr 55.

of Park and Loan revenue.<sup>1385</sup> He adds that Midstream does not charge GIK on Park and Loan Services.<sup>1386</sup>

Mr. Decker states that DTE Gas provides transportation services to off-system customers who want to transport gas across DTE Gas's transmission system from a specified receipt point location to a different delivery point location.<sup>1387</sup> Mr. Decker adds that Midstream is forecasting \$73.2 million in transportation revenue for the projected test period, which includes \$60.4 million in Off-System Transportation revenue and \$12.8 million in Exchange revenue.<sup>1388</sup>

Mr. Decker states that Exchange Services are transportation services that facilitate a contemporaneous exchange of gas on a Gas Day.<sup>1389</sup> He adds that Midstream is projecting \$12.8 million in Exchange revenue for the test year, with the three-year average annual Exchange revenue 2020 through 2022 being used to develop the test year forecast.<sup>1390</sup>

Mr. Coppola states that while DTE's the revenue forecasts for Contract Storage and Park & Loan are reasonable, DTE's revenue forecasts for Off-System Transportation and Exchange Gas services are significantly understated.<sup>1391</sup> He adds that DTE provided actual revenues from 2018 to 2023, and provided the monthly adjustments made to monthly gas deliveries to DTE Electric from January 2020 to May 2022, which were previously included with Exchange Gas Services and beginning in June 2022 are included

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<sup>1385</sup> 2 Tr 57.

<sup>1386</sup> 2 Tr 62.

<sup>1387</sup> Id.

<sup>1388</sup> Id.; Ex. A-13, Sch. C3.3.

<sup>1389</sup> 2 Tr 65.

<sup>1390</sup> 2 Tr 66; Ex. A-13, Sch. C3.3.1.

<sup>1391</sup> 4 Tr 1521.

with Off-System Transportation services.<sup>1392</sup> He states that he calculated revised forecasted revenue for Off-System Transportation revenue of \$63,779,000 using the most recent three years of actual revenues (2021-2023) after adjusting for the DTE Electric volumes, which revised revenue is \$3,398,000 higher than DTE's projected test year revenue of \$60,381,000.<sup>1393</sup> Similarly, for Exchange Gas Services, he calculated revised revenues of \$15,625,000 for the projected test year, which amount is \$2,832,000.<sup>1394</sup> Thus, he recommends that the Commission adopt these more recent revenue forecasts and increase DTE's projected test year revenues by the total amount of \$6,230,000.<sup>1395</sup>

Mr. Decker counters that while using historical averages is appropriate for calculating Exchange Services revenue, the proper methodology in this rate case, as with prior Case Nos. U-20642, and U-20940, is to use the 3-year average ending with the historical period, which for this case is 2022.<sup>1396</sup> In its brief, the Attorney General points out that in discovery DTE acknowledges that gas markets were affected by COVID in 2020.<sup>1397</sup>

Regarding, Mr. Coppola's adjustment for Off-System revenue, Mr. Decker counters that utilizing an average for the Off-System Transportation services forecast is not the appropriate methodology to use for this service; rather the appropriate methodology is to add revenue already under contract to the estimated revenue for assets

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<sup>1392</sup> 4 Tr 1522; Ex. AG-36.

<sup>1393</sup> 4 Tr 1522; Ex. AG-37.

<sup>1394</sup> *Id.*

<sup>1395</sup> *Id.*

<sup>1396</sup> 2 Tr 123.

<sup>1397</sup> Attorney General initial brief, p. 86, citing Ex. Ag-62, p. 5-6.

available for sale, which methodology has been utilized and approved in Case Nos. U-18999, U-20642, and U-20940.<sup>1398</sup>

This PFD agrees with the Attorney General regarding Exchange Services revenue, finding that it is more reliable to use the most recent information which excludes an anomalous year (2020) adversely affected by COVID. However, this PFD agrees with DTE regarding Off-System Transportation as using revenue under contract is the best approach for estimating future revenue.

### **Other Operating Revenue**

DTE projects DTE Gas's other operating revenue is projected to be \$143.8 million, consisting of (1) late payment/NSF revenue, (2) appliance service programs, (3) miscellaneous service revenue, (4) gas choice supplier revenues, (5) rent from gas property, (6) inter-department rent, (7) other gas revenues, (8) GIK, (9) Blue Lake investment income, (10) Vector Lease interest, and (11) Grantor Trust income.<sup>1399</sup>

### **Home Protection Plus (HPP) Appliance Service Program**

Mr. Decker states that this program provides appliance repair services performed by DTE Gas field service employees and selected vendors pursuant to a one-year service agreement between DTE and residential customers.<sup>1400</sup> He adds that the revenues associated with these programs in the projected test year are included as a reduction in the overall cost of service to customers, and that DTE expects to maintain its enrollment levels and revenues consistent with the historical test period of approximately 223,600 customer enrollments and \$99.3 million in gross revenue.<sup>1401</sup>

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<sup>1398</sup> 2 Tr 124.

<sup>1399</sup> DTE initial brief, p. 90: Ex. A-13, Sch. C3.

<sup>1400</sup> 2 Tr 82.

<sup>1401</sup> 2 Tr 83; Ex. A-13, Sch. C3.

Mr. Coppola states that the profit margin is the difference between program revenues and related program expenses, and that DTE forecasted the same revenue of \$99.3 million for the HPP/ASP for the projected test year as it billed for 2022.<sup>1402</sup> He adds that DTE provided the actual revenues for the HPP/ASP from 2018 to 2023 with related operating expenses, which shows a steady increase in revenues, with 2023 revenues reaching \$103.9 million, or \$4.0 million above the 2022 level, which also shows the profit margin or net operating income between revenues and operating expenses.<sup>1403</sup> He asserts that it is apparent that the year 2022 is not representative of the revenue and profit margin earned in the most recent year of 2023, or in any of the prior five years; that is, using the 2022 revenues, operating expenses, and profit margin as a proxy for future test year amounts would result in an inaccurate and unreasonable forecast amount.<sup>1404</sup>

Mr. Coppola proposes to use the actual revenue of \$103,901,000 for 2023 and the related operating expenses of \$73,602,000 with the profit margin of \$30,299,000, as the best forecast of operating income for the projected test year, which results in an increase in operating income of \$4,617,000 over the DTE's forecast.<sup>1405</sup> Thus, he recommends that the Commission adopt the 2023 revenue and operating expenses shown in Exhibit AG-38 and increase DTE's projected operating income by \$4,617,000.<sup>1406</sup>

Mr. Decker counters that the Appliance Repair Service is subject to intense competition in the marketplace from independent contractors and other repair service companies, as evidenced by the fact that average contracts decreased from the historical

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<sup>1402</sup> 4 Tr 1523; Ex. A-13, Sch. C3.

<sup>1403</sup> Id; Ex. AG-38.

<sup>1404</sup> Id.

<sup>1405</sup> 4 Tr 1523-1524.

<sup>1406</sup> 4 Tr 1524.

test period of 2022 to 2023.<sup>1407</sup> He adds that if the Commission were to consider an alternative methodology to smooth yearly variations in the different components that make up profit margin, DTE suggests adopting a 3-year average of the profit margin percentage (against revenue for the corresponding year) and applying this percentage to the most recent available full year revenue actual.<sup>1408</sup> He states that using this methodology, the average profit margin for 2021-2023 is 26.45%, and that using this average profit margin percentage against the 2023 actual revenue of \$103,901,000, results in a profit margin of \$27,483,000 versus a profit margin of \$25,682,000 in 2022 (the historical test year), or an increase of \$1,801,000 as opposed to Witness Coppola's proposed increase of \$4,617,000.<sup>1409</sup>

In its brief, the Attorney General states that in its discovery response, DTE admits that in the past five years from 2019 – 2023, the revenues, net operating income after expenses, and profit margins for this program have increased each year.<sup>1410</sup>

This PFD agrees with the Attorney General, as DTE has failed to support a reasoned opposition to using the 2023 revenue and operating expenses. Thus, this PFD recommends that the Commission adopt the Attorney General's proposal to increase DTE's projected operating income by \$4,617,000.

Mr. Decker states that the HPP Check Reimbursement Solution and the HPP Customer Relationship and Billing Enhancements projects span across the historical test year (2022) and bridge period (21 months ending 09/30/2024).<sup>1411</sup> He states that the HPP

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<sup>1407</sup> 2 Tr 126.

<sup>1408</sup> *Id.*

<sup>1409</sup> 2 Tr 126-127.

<sup>1410</sup> Attorney General initial brief, p. 89, citing Ex. AG-63, p. 1,2.

<sup>1411</sup> 2 Tr 84.

Check Reimbursement Solution replaces a technology that is used to facilitate payments for the HPP program customers that reach end of life on their appliances and are contractually entitled to partial reimbursement for the cost of that appliance replacement under DTE's Greenbacks program.<sup>1412</sup> Mr. Decker states that the HPP Customer Relationship and Billing Enhancements were to add functionality to bill and dispatch additional HPP plans which assist customers whose equipment cannot be repaired, improvements in our service order dispatching process to provide our customer service agents with more customer focused messaging and better communication to the customer regarding their upcoming service call.<sup>1413</sup>

Mr. Decker states that Gas Customer Choice (GCC) customers consist of residential and business customers who elect to purchase their natural gas commodity from Alternative Gas Suppliers (AGS) rather than purchase GCR supply from DTE.<sup>1414</sup> He adds that the AGSs are responsible for delivering gas supply on behalf of their customers while DTE Gas retains responsibility for the gas distribution, including maintaining facilities, responding to leaks and other emergencies, reading customer meters, performing all billing, remittance, and collection activities, and responding to all customer inquiries other than those related to the AGS's natural gas supply service offering.<sup>1415</sup> He states that DTE Gas projects revenue for this category of \$1.3 million.<sup>1416</sup>

Mr. Decker states that this revenue is driven by miscellaneous charges and services provided to third parties, and includes receipt point revenue, Michigan tax

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<sup>1412</sup> 2 Tr 85.

<sup>1413</sup> 2 Tr 87.

<sup>1414</sup> 2 Tr 88.

<sup>1415</sup> 2 Tr 88-89.

<sup>1416</sup> 2 Tr 90.; Ex. A-13, Sch. C3.

revenue, City of Detroit tax revenue, and non-cash customer credits.<sup>1417</sup> He adds that DTE Gas projects revenue for this category of \$1.3 million.<sup>1418</sup>

Mr. Decker states that Blue Lake Investment Income results from DTE Gas's 25% equity ownership in Blue Lake Gas Storage Company (Blue Lake), which is a 48 Bcf storage facility in Northern Michigan that is jointly owned by Blue Lake Holdings (DTE Gas Company) and ANR Blue Lake Company (TC Energy).<sup>1419</sup> He adds that Blue Lake investment income is forecasted to be \$1.3 million in the projected test year compared to \$2.4 million in the historical test period.<sup>1420</sup>

Mr. Decker states that Merchant transaction fees are transactional costs that are associated with the processing of debit and credit card payments.<sup>1421</sup> He adds that the volume of customers using debit or credit payment options one or more times in a given year has increased by 35% over the last seven years, from less than 0.54 million in 2016 to over 0.73 million in 2022.<sup>1422</sup> He states that the average monthly customer merchant fee paid by DTE for residential and non-residential customers in 2022 was \$0.94 and \$4.72, respectively.<sup>1423</sup> He adds that from 2016 to 2018, non-residential merchant fee expense grew over 50%, increasing from \$1.03 million in 2016 to \$2.43 million in 2018, and from 2019 to 2021, merchant fee expense decreased by 30%, from \$2.94 million in 2019 to \$1.99 million in 2021, which is attributable to mitigation efforts.<sup>1424</sup> He states that

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<sup>1417</sup> Id.

<sup>1418</sup> Id.

<sup>1419</sup> 2 Tr 91.

<sup>1420</sup> 2 Tr 92; Ex. A-13, Sch. C3.

<sup>1421</sup> Id.

<sup>1422</sup> 2 Tr 93, Table 5.

<sup>1423</sup> Id., Table 6.

<sup>1424</sup> 2 Tr 95.

DTE is forecasting and seeking recovery of \$6.26 million of merchant fees in the test year.<sup>1425</sup>

Mr. Coppola states that although DTE in recent years began to limit the use of credit/debit cards for non-residential customers, the cost is still rather significant, noting that for the projected test year, DTE forecasted \$4,042,000 in merchant fees pertaining to residential customers and \$2,218,000 for non-residential customers, for a total forecasted expense of \$6,260,000.<sup>1426</sup> He proposes that the Commission disallow recovery of merchant fees for non-residential customers beginning with the costs included in the projected test year in this rate case, which proposal will remove \$2,216,000 from forecasted expense for the projected year.<sup>1427</sup> Thus, he recommends that the Commission disallow recovery of the \$2.2 million of merchant fees pertaining to non-residential customers so that DTE can take appropriate actions to avoid those costs beginning with the projected test year in this rate case.<sup>1428</sup>

Mr. Decker counters that DTE does not agree that non-residential customers should be charged a convenience fee to utilize a credit / debit card to pay their utility bill as the Attorney General suggests – asserting that business customers appreciate the flexibility and convenience to choose a card payment transaction.<sup>1429</sup> He adds that DTE has implemented mitigation policies to decrease non-residential merchant fees.<sup>1430</sup> He states that DTE believes that the 54,000 non-residential customers that utilized a card

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<sup>1425</sup> Id.; Ex. A-13, Sch. C5.8.

<sup>1426</sup> 4 Tr 1552.

<sup>1427</sup> 4 Tr 1553.

<sup>1428</sup> 4 Tr 1554.

<sup>1429</sup> 2 Tr 134.

<sup>1430</sup> Id.

payment last year are largely small business customers that often utilize credit cards to run their businesses.<sup>1431</sup>

This PFD agrees with DTE that business customers apparently appreciate the flexibility and convenience to choose a card payment transaction as evidenced by the large number of customers who are doing so. Thus, this PFD recommends that the Commission reject the Attorney General's proposed disallowance.

### **Operating and Maintenance Expenses**

DTE projects an increase in O&M expense from the historical period to the projected test year of \$75.2 million due primarily to inflation, higher transmission and distribution expenses, higher benefits expense, and increased shared asset fees from DTE Electric.<sup>1432</sup> He adds that starting with the historical test year amount of \$463.1 million and adding forecasted adjustment for general inflation and for Administrative and General expense result in a projected base O&M expense of \$538.3 million for the twelve months ending September 30, 2025.<sup>1433</sup>

### **Inflation**

DTE states that it used a 2022 historical test year and assumed inflation rates of 3.2% in 2023, 2.9% in 2024, and 2.2% in 2025, and then calculated a composite inflation rate based on a labor factor and a non-labor factor.<sup>1434</sup> DTE states that the composite labor component factor is 3% and consists of rates for represented employees and non-represented employees.<sup>1435</sup> DTE asserts that for represented employees, DTE is

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<sup>1431</sup> 2 Tr 135.

<sup>1432</sup> 4 Tr 2314; ex. A-13, Sch. C1

<sup>1433</sup> 4 Tr 2314-2315; Ex. A-13, C5.

<sup>1434</sup> DTE initial brief, p. 92. Citation omitted.

<sup>1435</sup> Id.

obligated under existing Collective Bargaining Agreements to increase pay rates by at least 3% annually through the term of the contracts, and that this rate is also used for contract employees, since a portion of DTE Gas's contract workforce is sourced from the same unions as DTE union employees.<sup>1436</sup> DTE adds that non-represented employees also generally received an overall pay increase of 3%, based largely on pay practices of other employers, changes in the external competitive market, and internal pay equity, which 3% adjustment for non-represented employees is comparable to annual pay adjustments since 2010.<sup>1437</sup> DTE states that for non-labor costs, the inflation rate is based on a consumer price index (CPI)-Urban from IHS Markit in August 2023, and thus, that these labor-and non-labor rates were then used to calculate a composite inflation rate for 2023, 2024, and a 9-month proration for 2025.<sup>1438</sup>

Mr. Coppola states that he disagrees with DTE's inflationary cost increases included in the projected test year O&M expense.<sup>1439</sup> Mr. Coppola notes that DTE shows that \$30.4 million of the total other O&M expense increase of \$75.2 million pertains to inflationary cost increases calculated by DTE based on a blend of the Consumer Price Index (CPI) forecasted inflation rate and a 3% forecasted annual wage increase for union, non-union, and contractor employee costs, with the blended annual inflation rates developed by DTE being 3.2% for 2023, 2.9% for 2024, and 2.9% for 2025.<sup>1440</sup> Mr. Coppola counters that the use of a "blended rate" inclusive of wage increases has been rejected in recent general rate cases and instead, the Commission has previously

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<sup>1436</sup> Id.

<sup>1437</sup> Id.

<sup>1438</sup> Id.

<sup>1439</sup> 4 Tr 1529-1530.

<sup>1440</sup> 4 Tr 1530; Ex. A-13, Sch. C5.

adopted the use of the CPI-Urban area inflation rates to forecast future cost increases when warranted.<sup>1441</sup> He adds that the Commission has made it clear that it expects utilities to create cost efficiencies from the implementation of IT systems and other technology, and that those efficiencies should translate into tangible cost savings that reduce, and potentially even fully offset, future cost increases.<sup>1442</sup>

Mr. Kehoe states that DTE Gas projects a total of \$246.8 million of direct O&M expenses, adjusted for Company Use Reclassification, during the projected test year ending September 30, 24 2025.<sup>1443</sup> He adds that Inflation rates for the bridge period and projected test period are 3.2% for the calendar year 2023, 2.9% for calendar year 2024, and 2.2% for January through September 30, 2025.<sup>1444</sup>

Mr. Kehoe states that the projected test period O&M for natural gas storage, excluding the cost of Company Use gas, is \$15.2 million out of the total \$246.8 million.<sup>1445</sup> He adds that to calculate the projected amount, inflation was applied to the adjusted actual 2022 historical test period, with the adjusted historical 2022 O&M expense for natural gas storage being \$13.7 million excluding Company Use.<sup>1446</sup> He states that in addition to inflation, DTE Gas is projected to incur an additional \$0.38 million for routine logging, reflected in Other Projected Adjustments, and that the projected test period O&M for Additional Routine Logging is \$1.84 million.<sup>1447</sup>

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<sup>1441</sup> Id.

<sup>1442</sup> Id.

<sup>1443</sup> 4 Tr 1998-1999, Table 1.

<sup>1444</sup> Id.

<sup>1445</sup> 4 Tr 2000; Ex. A-13, Sch. C5.1.

<sup>1446</sup> Id.

<sup>1447</sup> 4 Tr 2001-2002, Table 2; Ex. A-13, Sch. C5.1.

Mr. Kehoe states that the projected test year O&M for transmission expense, excluding the cost of Company Use gas, is calculated at \$89.7 million out of the total \$246.8 million of projected test year O&M expense.<sup>1448</sup> He adds that to calculate the projected amount, inflation was applied to the adjusted actual 2022 historical test period expense, and the adjusted historical 2022 O&M expense for transmission expense is \$60.5 million excluding Company Use Gas.<sup>1449</sup> He states that in addition to inflation, DTE Gas is projected to incur an additional \$24.1 million of Other Projected Adjustments included in the \$89.7 million transmission O&M expense.<sup>1450</sup>

Mr. Kehoe states that the projected test period O&M for natural gas distribution, excluding the cost of Company Use gas, is \$141.9 million out of the total \$246.8 million.<sup>1451</sup>

Mr. Coppola states that DTE provided actual 2023 O&M expense information with significant cost savings achieved in 2023, with DTE reporting that actual other O&M expense for 2023 was \$466.1 million, and after eliminations, reclassifications, and normalizations, it incurred \$452.1 million of proforma O&M expense.<sup>1452</sup> Mr. Coppola adds that he used this new base of expense adjusted for \$103.6 million of cost items that are not directly affected by inflation, and applying the inflation rate of 2.6% for 2024 and 2.2% for 9 months of 2025, he calculated the cumulative inflation adjustment of \$14,961,000.<sup>1453</sup> He notes that in comparison, DTE had calculated an inflation adjustment

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<sup>1448</sup> 4 Tr 2002-2003; Ex. A-13, Sch. C5.2.

<sup>1449</sup> Id.

<sup>1450</sup> 4 Tr 2010; Ex. A-13, Sch. C5.2.

<sup>1451</sup> 4 Tr 2028; Ex. A-13, Sch. C5.3.

<sup>1452</sup> 4 Tr 1530-1531; Ex. AG-44.

<sup>1453</sup> 4 Tr 1531; AG-45.

for the same 21 months of \$18,962,000, with a difference of \$4,001,000.<sup>1454</sup> He states that the \$4,001,000 reduction in inflation adjustments reflects the change from blended inflation rates to using only the CPI forecasted inflation rate and also the lower base of O&M expense for 2023 normalized and adjusted by DTE.<sup>1455</sup> Thus, he recommends that the Commission adopt his inflation cost adjustment and remove \$4,001,000 from the DTE forecasted O&M expense for the projected test year.<sup>1456</sup>

ABATE also disagrees with DTE's proposed inflation rates. Mr. Fitzhenry asserts that did not produce any supporting workpapers to support the 3.0% assumption for the expected labor cost escalation assumption.<sup>1457</sup> He adds that if DTE is experiencing increased labor cost, they could have supported the 3.0% wage inflation rate with supporting workpapers, but absence any direct evidence demonstrating increased company labor cost, the 3.0% wage inflation rate should not be relied on to escalate O&M expense.<sup>1458</sup> He suggests that DTE use the Blue Chip GDP Chained Price Index for the O&M inflation factors, as the wage inflation rate used by DTE is not well supported, and the CPI-U non-labor inflation rate is well above the consensus industry experts' opinion of the GDP Chained Price Index.<sup>1459</sup> He states that his recommended adjustment to the inflation factor reduces DTE's proposed O&M expense by approximately \$6.9 million.<sup>1460</sup>

DTE counters that it fully supported the calculation of a weighted average composite inflation rate.<sup>1461</sup> DTE asserts that it is inappropriate to selectively update the

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<sup>1454</sup> Id.

<sup>1455</sup> Id.

<sup>1456</sup> Id.

<sup>1457</sup> 4 Tr 1323.

<sup>1458</sup> Id.

<sup>1459</sup> 4 Tr 1324.

<sup>1460</sup> 4 Tr 1325, Table CTF-6.

<sup>1461</sup> 4 Tr 1873.

non-labor inflation rate for the test period without also accounting for an updated labor rate for the test period, noting that the non-labor rates used by Mr. Coppola are already outdated and have since increased for those respective time periods.<sup>1462</sup> DTE argues that should the Commission choose to incorporate an updated non-labor inflation rate to calculate projected test period O&M expense in a final order in this proceeding, it would be appropriate to use the most recent CPI-U rate sponsored by Ms. Uzenski and the updated labor rate sponsored by Mr. Cooper shown in DTE Exhibit A-34, Schedule X1.

In its brief, the Attorney General notes that DTE acknowledges that DTE's updated inflation rates shown in Ex. A-34, Sch. X1 use a blend of labor wage increases and CPI-U forecasted rates.<sup>1463</sup>

This PFD agrees with the Attorney General, finding that the Attorney General's proposed adjustments are reasonable and supported. This PFD notes that the Commission customarily applies that CPI-Urban inflation rate used by the Attorney General and that the Commission does not support DTE's use of a blended inflation rate.<sup>1464</sup> This PFD notes that ABATE does not provide support for its assertion that the CPI-U non-labor inflation rate is well above the consensus industry experts' opinion of the GDP Chained Price Index. Thus, this PFD recommends that the Commission adopt the Attorney General's proposed disallowance of \$4,001,000.

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<sup>1462</sup> *Id.*

<sup>1463</sup> Attorney General initial brief, p. 98, citing Ex. AG-71.

<sup>1464</sup> See, Case No. U-20561, Order, May 8, 2020, p. 86 ("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."); Case No. U-20940, Order, December 9, 2021, p. 120 ("The Commission . . . finds that the Staff's proposed use of updated CPI-Urban inflation projections using actual 2020 inflation of 1.24% and updated projections of 2.47% for 2021 and 1.93% for 2022 should be approved. The Commission does not support DTE Gas's use of a blended inflation rate. As noted on the record, the Commission has previously rejected this approach in general rate cases.").

Mr. Coppola states that DTE Gas took a number of measures to reduce 2023 costs due to financial challenges at both DTE and its affiliate DTE Electric Company that resulted in lower O&M expenses, such that the base O&M expense before reclassifications and normalizations fell from \$527.2 million in 2022 to \$466.1 million in 2023.<sup>1465</sup> He asserts that the decrease in expense of \$61.1 million reflects primarily avoided overtime, deferred training and expenses, lower employee levels from deferred hiring, and work with contractors also being deferred.<sup>1466</sup> He adds that in discovery DTE normalized the actual expense for 2023 stating that most of those costs would return in subsequent years.<sup>1467</sup> Mr. Coppola states that even after normalizing the 2023 O&M expenses to \$452.1 million, those costs are still lower than the 2022 historical normalized expenses of \$463.1 million by \$11.0 million.<sup>1468</sup> He states that he compared the normalized 2023 O&M expense of \$452.1 million to DTE's forecasted O&M expenses of \$474.5 million for the same year to calculate O&M expense savings of \$22,431,000, which should be included in the projected test year.<sup>1469</sup> He asserts that the actual normalized 2023 O&M expense of \$452.1 million recently provided by DTE shows that the \$474.5 million forecasted by DTE is no longer reasonable and indeed that projected test year O&M expense filed by DTE and built-up from a stale 2022 base is overstated by \$22,431,000.<sup>1470</sup> Thus, he recommends that the Commission remove this additional amount of \$22,431,000 from DTE's projected test year O&M expense.<sup>1471</sup>

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<sup>1465</sup> 4 Tr 1532; Ex. AG-44.

<sup>1466</sup> Id.

<sup>1467</sup> Id.

<sup>1468</sup> Id.

<sup>1469</sup> Id.; Ex. AG-45.

<sup>1470</sup> 4 Tr 1533; Ex. AG-44.

<sup>1471</sup> Id.

DTE counters that the Attorney General's methodology is flawed, with her proposal to reset O&M using historical 2023 actuals violating the regulatory construct of using a historical test year as adjusted for known and measurable changes.<sup>1472</sup> DTE asserts that facts and circumstances continue to change daily once a filing is made and that updating for just one item is simplistic and ignores other changes that may have occurred.<sup>1473</sup> Regarding O&M expenses for transmission, DTE states that it incorporates a known and measurable reduction in O&M expense for the Washington 10 contract expiration of \$2.385 million for the projected test year, which Mr. Coppola's proposed disallowance of \$1.755 million for the Washington 10 contract expiration is a duplication of the known and measurable change already included in the test year, such that Mr. Coppola's proposed disallowance must be increased by \$1.755 million for the known and measurable change relating to the Washington 10 contract expiration.<sup>1474</sup> Similarly, for the Customer Service O&M expenses, DTE asserts that it incorporated a known and measurable reduction in O&M expenses for call volume savings of \$3.3 million with which Mr. Coppola's proposed disallowance overlaps and thus must be adjusted.<sup>1475</sup>

This PFD agrees with the Attorney General. Recognizing the known and measurable cost savings that DTE undertook (as normalized by DTE which included \$57.7 million of cost add-backs for temporary cost reductions<sup>1476</sup>) is appropriate in formulating projected test year expenses. Moreover, contrary to DTE's assertion, the Attorney General's proposed disallowance includes specific expense savings from all

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<sup>1472</sup> DTE initial brief, p. 95. Citations omitted.

<sup>1473</sup> *Id.*

<sup>1474</sup> *Id.*

<sup>1475</sup> *Id.*, p. 100-101.

<sup>1476</sup> See Ex. AG-45, first note.

seven categories of DTE's O&M expenses. This PFD agrees that the proposed disallowance amount needs to be adjusted to reflect the two instances where the disallowances overlapped with adjustments that DTE made. According, this PFD recommends that the Commission adopt the Attorney General's proposed disallowance in an adjusted amount of \$17,379,000.<sup>1477</sup>

Mr. Coppola states that DTE has initiated additional cost reductions that will further reduce O&M expense in the projected test year.<sup>1478</sup> He adds that in discovery, DTE stated that in January 2024, it offered a Voluntary Separation Incentive Plan to 422 DTE Gas employees and 1,622 DTE Corporate Services employees and that up to \$6.3 million of labor cost savings could be achieved in 2025.<sup>1479</sup> He adds that the \$6.3 million does not include employee benefit savings from lower active health care costs, 401K plan matching, and other benefits.<sup>1480</sup> He recommends a reduction only half, or \$3.2 million, of the currently estimated labor cost savings of \$6.3 million as a reduction to the O&M expense for the projected test year.<sup>1481</sup>

DTE states that the Transmission Integrity Management Program (TIMP) is a federally mandated program to identify and mitigate risks to transmission pipeline systems.<sup>1482</sup> Mr. Kehoe states that the projected test period O&M for TIMP Pipeline Integrity is \$23.01 million.<sup>1483</sup> He adds that in the historical test year of 2022, \$16.34 million was spent resulting in a known and measurable change of \$6.67 million for the

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<sup>1477</sup> \$22,431,000 - \$1,755,000 - \$3,297,000 = \$17,379,000.

<sup>1478</sup> Id.

<sup>1479</sup> 4 Tr 1533; Ex. AG-46.

<sup>1480</sup> 4 Tr 1533-1534.

<sup>1481</sup> 4 Tr 1534; Ex. AG-46.

<sup>1482</sup> 4 Tr 2008.

<sup>1483</sup> 4 Tr 2012, Table 3: DTE initial brief, p. 95.

projected test period.<sup>1484</sup> He states that the increased expenses are due to the assessments that are planned to be conducted in the projected tested period, adding that for comparison, there were nine assessments in the historical test year and ten assessments on average in the projected test period.<sup>1485</sup> He asserts that the increase in pipelines DTE is assessing is due to the continual execution of the In- Line Inspection (ILI) Expansion program.<sup>1486</sup>

Mr. Coppola states that for the historical 2022 period, DTE had expenses of \$16.3 million for Transmission Integrity Management Program (TIMP) and for the projected test year, DTE forecasted expenses of \$23.0 million, which is a \$6.7 million increase over 2022.<sup>1487</sup> Noting that in Case No. U-20642 that DTE forecasted an increase of \$8.4 million for TIMP Pipeline Integrity for the projected test year ended September 2021 from the 2018 historical expense of \$10.3 million, which should have placed the total expense at more than \$18 million for the 12 months ended September 2021, he asserts that the forecasted ramp up in TIMP Pipeline Integrity expense has not materialized as forecasted.<sup>1488</sup> He states that DTE reported only \$10.3 million of expense in 2020 and 13.5 million for 2021, after DTE had increased the expense level to just over \$17 million in 2019.<sup>1489</sup> He adds that since 2021, when expenses reached \$18.6 million, DTE has steadily reduced pipeline inspection costs to \$16.3 million in 2022 and \$8.6 million in 2023 with the number of inspections dropping from in 2021 to only 4 in 2023.<sup>1490</sup> He asserts

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<sup>1484</sup> Id.

<sup>1485</sup> 4 Tr 2012.

<sup>1486</sup> Id.

<sup>1487</sup> 4 Tr 1534.

<sup>1488</sup> 4 Tr 1535.

<sup>1489</sup> 4 Tr 1535.

<sup>1490</sup> Id.

that DTE has not made a consistent commitment to a higher expense level in order to achieve the 7-year inspection cycle and will likely spend less than it requested in Case No. U-20642.<sup>1491</sup> He argues that this lack of consistency in spending to achieve the 7-year inspection cycle undermines DTE's credibility about its expense forecast of \$23.0 million for the projected test year in this rate case.<sup>1492</sup>

Mr. Coppola states that in connection with DTE's 2023 O&M expenses, DTE provided normalized transmission pipeline inspection expenses of \$16.6 million for 2023 after a normalizing adjustment of \$7.5 million.<sup>1493</sup> He asserts that the normalized expense for 2023 is \$1.5 million higher than the average expense of the past three years, such that the \$23.0 expense level forecasted by DTE for the projected test year is not credible and not likely to be incurred given the historical record.<sup>1494</sup> Thus, he recommends that the Commission reject the expense increase of \$6.7 million from 2022 to the projected test year and remove this amount from DTE's forecasted test year O&M expense.<sup>1495</sup>

Mr. Kehoe counters that utilizing pipeline integrity project historical O&M spend as the lone factor to determine O&M expense for pipeline integrity projects in the projected test year is not reasonable, as project requirements from year to year can change significantly.<sup>1496</sup> He states that DTE Gas forecasts its expenses on the best information available at the time by utilizing detailed project cost estimates along with historical spend for similar types of projects.<sup>1497</sup> He adds that although historical assessment costs offer

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<sup>1491</sup> Id.

<sup>1492</sup> Id.

<sup>1493</sup> Id.; Ex. AG-44.

<sup>1494</sup> 4 Tr 1535-1536.

<sup>1495</sup> 4 Tr 1536.

<sup>1496</sup> 4 Tr 2050.

<sup>1497</sup> Id.

some insight into the future cost of assessments, the amount or type of remediation work is very difficult to predict.<sup>1498</sup>

This PFD agrees with the Attorney General. While the amount of remediation work is difficult to predict, historical costs do provide insight as to appropriate future expenditures. Moreover, DTE has not rebutted the Attorney General's assertion that DTE has steadily reduced pipeline inspection costs since 2021 with the number of inspections also dropping since 2021. In addition, this PFD notes that DTE started using the ILI Expansion program in 2012, such that the history of work under the program is not so limited as to be unreliable for comparison purposes.<sup>1499</sup> Thus, this PFD recommends that the Commission adopt the Attorney General's proposed disallowance.

DTE states that MAOP Records Review is the review of pipeline records to ensure that the records are traceable, verifiable and complete (TVC), and substantiate Maximum Allowable Operating Pressure (MAOP).<sup>1500</sup> Mr. Janness states that DTE Gas implemented the MAOP Records Review program in 2011 and has developed a MAOP Reconfiguration plan and is implementing the plan to remediate defects earlier than required by the rules.<sup>1501</sup>

Mr. Coppola states that although the requirements that transmission pipeline operators have adequate records to verify the MAOP and other pipeline operating characteristics was preliminary issued in 2011, it does not mean that DTE should not have kept adequate records of the construction of its pipelines and facilities prior to that

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<sup>1498</sup> 4 Tr 2051.

<sup>1499</sup> 4 Tr 614.

<sup>1500</sup> 4 Tr 618.

<sup>1501</sup> 4 Tr 620.

date.<sup>1502</sup> He asserts that DTE has the sole responsibility to ensure it maintains adequate records of its pipelines and related facilities, both now and in the past, and the fact that adequate records do not exist is not a problem that should be remedied entirely on the backs of customers.<sup>1503</sup> He argues that although a strong argument can be made that the cost to remedy the record gaps should be entirely absorbed by DTE, it is fair and reasonable for DTE to absorb at least 50% of the cost and recover the other 50% in base rates, as an accommodation for the long passage of time since the pipeline was installed.<sup>1504</sup> Thus, he recommends that the Commission remove \$875,000 (50% of \$1,750,000) from the O&M expense proposed by DTE for the projected test year.

DTE counters that Mr. Coppola's assertions are unsupported. DTE notes that Mr. Coppola provides no requirement, regulation, or law prior to 2011 that obligates DTE Gas to keep adequate records of its pipelines and facilities.<sup>1505</sup> DTE adds states that DTE Gas has demonstrated how it has complied with the applicable regulations and requirements.<sup>1506</sup> DTE asserts that has provided ample evidence about why these remediation and reconfirmation costs are necessary in order to remain compliant with currently applicable rules and regulations.<sup>1507</sup>

This PFD agrees with DTE, which has adequately supported its projected O&M expenses. Moreover, it is unreasonable to purport to hold DTE to asserted best practices before applicable regulations mandated those practices as such. Thus, this PFD

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<sup>1502</sup> 4 Tr 1537.

<sup>1503</sup> 4 Tr 1538.

<sup>1504</sup> *Id.*

<sup>1505</sup> DTE initial brief, p. 98.

<sup>1506</sup> *Id.*

<sup>1507</sup> *Id.*, p. 98-99.

recommends that the Commission reject the Attorney General's proposed disallowance be rejected.

DTE included O&M costs related to compliance with the Gas Pipeline Leak Detection Notice of Proposed Rulemaking (NPRM). Mr. Kehoe states that DTE Gas expects to spend \$10.3 million during the projected test period and that over the three-year period of 2025 – 2027, DTE Gas expects to spend \$44.79 million, which averages out to approximately \$14.92 million per year.<sup>1508</sup> He adds that the effective date of the LDAR rule is expected to go into effect six months after the final rule is published, such that the effective date is estimated to be March 1, 2025.<sup>1509</sup> DTE states that if the Commission removes LDAR costs from the rate case, DTE alternatively requests that a regulatory deferral mechanism be implemented for recovery of these costs.<sup>1510</sup>

Mr. Coppola states that, it is still unknown when the new rule will be issued and how soon thereafter DTE will be required to be fully comply with the requirements within the new rule.<sup>1511</sup> He adds that even if DTE's expectations of an initial implementation date of March 1, 2025 were to occur, it will not likely be able to fully implement and spend the entire \$10.3 million by the end of project test year ending in September 2025, which is only seven months after the initial implementation date.<sup>1512</sup> He concludes that DTE has not adequately supported the need for the additional \$10.3 million of O&M expense for the LDAR program or made a convincing case that those additional expenses are needed

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<sup>1508</sup> 4 Tr 2040.

<sup>1509</sup> *Id.*

<sup>1510</sup> DTE initial brief, p. 99.

<sup>1511</sup> 4 Tr 1538.

<sup>1512</sup> 4 Tr 1538-1539.

in the projected test year.<sup>1513</sup> Thus, he recommends that the \$10.3 million be removed from DTE's forecasted O&M expense in the projected test year.<sup>1514</sup>

Similarly, Ms. Creisher states that Staff does not support DTE's proposed level of capital expenditures and O&M expenses.<sup>1515</sup> She recommends that LDAR O&M expenses in the amount of \$10,276,000 should also not be recovered in base rates at this time.<sup>1516</sup> She adds that Staff is supportive of DTE's request for a regulatory deferral mechanism if the Commission does not support recovery of LDAR costs.<sup>1517</sup>

DTE states that it recognizes that the NOPR is not yet final and that substantive changes could be made to the NOPR resulting in meaningful changes to the costs projected in this case.<sup>1518</sup> DTE requests that if the Commission disallows all of DTE's requested LDAR O&M expenses, the Commission should approve a regulatory deferral mechanism for recovery of these costs as it would remove concerns that the forecasted costs in this proceeding are too high or low.<sup>1519</sup> DTE notes that in Case No. U-18999 although the Commission found it was not reasonable to recover incremental O&M costs for a PHMSA rule that was not final, because of the importance of the safety issues associated with the rule, the Commission allowed DTE to record a regulatory asset for actual, prudently incurred costs of compliance with the final rule rather than simply disallowing the costs.<sup>1520</sup>

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<sup>1513</sup> 4 Tr 1539.

<sup>1514</sup> 4 Tr 1539.

<sup>1515</sup> 4 Tr 1792.

<sup>1516</sup> 4 Tr 1793.

<sup>1517</sup> *Id.*

<sup>1518</sup> DTE initial brief, p. 100.

<sup>1519</sup> *Id.* Citation omitted.

<sup>1520</sup> 4 Tr 1850.

This PFD agrees with the Attorney General and Staff that DTE's proposed LDAR O&M expenditures are premature and should not be recovered until such a time that the final LDAR rule is published, and the actual effective date is known. Thus, this PFD recommends that the Commission adopt the proposed \$20,276,000 disallowance. This PFD also agrees with DTE and Staff that the Commission should approve a regulatory deferral mechanism for recovery of these costs.

DTE Gas requests approximately \$1.8 million in corporate membership dues under Miscellaneous General Expenses, with approximately \$1.7 million in corporate membership dues account for the top four corporate memberships – the American Gas Association (AGA), Gas Technology Institute-Operations Technology Department (GTI-OTD), Gas Technology Institute-Utilization Technology Development (GTIUTD), and INGAA.<sup>1521</sup>

FLO takes issue with DTE's corporate membership dues. Mr. Koepfel asserts that DTE does not provide any evidence to support the value of these memberships to ratepayers.<sup>1522</sup> He adds that there are reasons to be concerned that these memberships are actually harmful to ratepayers, noting that Planet Detroit recently reported that the American Gas Association, of which DTE CEO Jerry Norcia is Chair, has been an active advocate for expanding gas service, resisting electrification and energy efficiency, and advocating for unproven carbon capture and storage technologies as the backbone of the possibility of net zero gas.<sup>1523</sup> He states that these organizations are organized in the interest of their members—natural gas distributors and producers—and have a history of

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<sup>1521</sup> DTE initial brief, p. 101-102; Ex. A-34, Sch. X3.

<sup>1522</sup> 4 Tr 1018.

<sup>1523</sup> 4 Tr 1019. Citation omitted.

advocating for those interests whether they align with ratepayer interests or not.<sup>1524</sup> Mr. Koeppel states that the Commission should disallow all corporate membership expenses for lack of support in the record.<sup>1525</sup> He asserts that at the bare minimum, the Commission should disallow corporate membership expenses for the American Gas Association and any other memberships that are formally controlled by and organized in the financial interest of gas producers and distributors rather than ratepayers.<sup>1526</sup> He adds that, moving forward, the Commission should require detailed documentation of corporate membership expenses and the corresponding customer benefits as a condition of DTE Gas's next rate case filing, as it did for DTE Electric in U-20836.<sup>1527</sup>

DTE counters that Mr. Koeppel mistakenly characterizes DTE's corporate membership dues as harmful.<sup>1528</sup> Mr. Decker states that the AGA membership provides strategic business intelligence, essential conferences, technical committees and various forums.<sup>1529</sup> He adds that the AGA facilitates collaboration regarding emerging issues facing the industry.<sup>1530</sup> He states that the GTI-OTD membership provides access to research and development (R&D) initiatives focusing on critical distribution system safety methods and pipeline integrity.<sup>1531</sup> He adds that the R&D benefits ratepayers by enhancing safety, improving reliability and integrity, developing new leak detection technologies while reducing methane emissions, and supporting other areas critical to reliable natural gas delivery.<sup>1532</sup> He states that that the Commission has previously

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<sup>1524</sup> *Id.*

<sup>1525</sup> 4 Tr 1020.

<sup>1526</sup> *Id.*

<sup>1527</sup> *Id.*, citing Case No. U-20836, Order, November 18, 2022, p. 308.

<sup>1528</sup> DTE initial brief, p. 102.

<sup>1529</sup> 2 Tr 141.

<sup>1530</sup> *Id.*

<sup>1531</sup> 2 Tr 142.

<sup>1532</sup> 2 Tr 143.

approved DTE's request to include \$600,000 per year for membership dues in the Gas Technology Institute-Operations and Technology Development (GTI-OTD) program in the December 9, 2021 order in Case No. U-20940.<sup>1533</sup> He asserts that the GTI-UTD membership provides access to research and development (R&D) initiatives focusing on natural gas technologies that benefit our DTE Gas residential, commercial, and industrial customers pertinent to the Michigan economy, energy plans, and climate.<sup>1534</sup> He adds that the Gas Technology Institute (GTI) is a leading gas technology-based R&D organization with the history, science, and engineering capability to support the development of technology-based solutions for industry, government, and consumers.<sup>1535</sup> He states that the Commission has previously approved DTE's request to include \$350,000 per year for membership dues in the Gas Technology Institute-Utilization Technology Development (GTI-UTD) program in the September 13, 2018 order in Case No. U-18999.<sup>1536</sup> He adds that membership in INGAA, which is a trade organization that focuses on natural gas transmission pipelines, provides DTE the ability to coordinate with industry on the development and operation of safe and reliable natural gas transportation and storage infrastructure.<sup>1537</sup>

This PFD agrees with FLO that DTE's projected membership dues are problematic. Despite being repeatedly directed by the Commission to provide detailed information of projected costs associated with membership fees and justification for why

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<sup>1533</sup> Id.20940

<sup>1534</sup> Id.

<sup>1535</sup> Id.

<sup>1536</sup> 2 Tr 145.

<sup>1537</sup> Id.

these costs are in customers' interests, DTE has failed to do so.<sup>1538</sup> As FLO points out, DTE's cursory direct testimony that its Ex. A-3, Sch. C15 "identifies allowable operating expenses for corporate memberships" is false; that exhibit does not identify expenses for corporate memberships. Nor does any other DTE direct testimony or exhibit do so, let alone explain why the projected costs are in customers' interests. Moreover, this PFD notes that DTE's somewhat more detailed exhibit and testimony (referenced above) in support of these projected costs were offered not in its direct case but rather by way of (improper) rebuttal testimony filed after Staff and other intervenors' testimonies were filed.

In addition, this PFD notes that DTE's general descriptions of the benefits gained from these memberships indicate apparent overlaps and redundancies among the different memberships, with repeated references to R&D initiatives focused on safety and reliability, and mutual assistance coordination across the industry. Indeed, this PFD notes that an example of the benefit of its participation in the AGA that DTE offers is pipeline safety information sharing between AGA and INGAA (of which DTE is also a member).<sup>1539</sup>

This PFD finds that DTE has not adequately and properly supported its proposed expenditures for these memberships and thus recommends that the Commission adopt a disallowance of \$1,779,000.

Ann Arbor asserts that DTE Gas should be required to track costs of lobbying local government officials, and that any costs associated with lobbying local government

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<sup>1538</sup> See, Case No. U-20561, Order, May 8, 2020, p. 200 (The Commission agrees that DTE needs "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."); Case No. U-20836, Order, November 18, 2022, p. 308 ("The Commission directs DTE Electric to file in its future rate cases an exhibit containing an itemized list of projected costs associated with membership fees and justification for why those costs are in customers' interest.")

<sup>1539</sup> 2 Tr 141.

officials should be disallowed.<sup>1540</sup> Dr. Stults states that she cannot quantify the recommended disallowance because DTE said it does not track any costs related to the lobbying of local governments.<sup>1541</sup> She recommends the Commission require DTE to keep records of the amount of time employees spend lobbying local officials so it can ensure such amounts are not included in rates.<sup>1542</sup>

DTE counters that Dr. Stults' exhibit shows that expenses related to lobbying of local government officials are not included in DTE Gas's rates and are not sought for recovery in this rate case.<sup>1543</sup> Additionally, DTE notes that its Exhibit A-13, Schedule C5.6 notes that \$220,000 in costs for "Regional Relations Expenses Political Advocacy" was removed as part of rate case adjustments.<sup>1544</sup> DTE concludes that any new requirement implementing special record keeping is unwarranted.<sup>1545</sup>

This PFD agrees with DTE and recommends that the Commission not adopt Ann Arbor's recommendation for additional recordkeeping.

### **Employee Benefits Expenses**

DTE projects employee pension and benefit expense of \$43.1 million.<sup>1546</sup> DTE states that this amount consists of post-retirement benefits such as pension costs, OPEB costs such as post-employment health care, the new hire retiree VEBA, and DTE Gas's Employee Savings Plan (ESP); active healthcare costs; and other benefits and costs such

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<sup>1540</sup> 3 Tr 523.

<sup>1541</sup> *Id.*

<sup>1542</sup> *Id.*

<sup>1543</sup> DTE initial brief, p. 104.

<sup>1544</sup> *Id.*

<sup>1545</sup> *Id.*

<sup>1546</sup> DTE initial brief, p. 104; Ex. A-13, Sch. C5.9 Revised.

as vacation expense, life insurance, and general benefit expenses and administration fees.<sup>1547</sup>

Mr. Cooper states that pension costs are those costs related to retirement benefits to the employees of DTE that are eligible to participate in DTE's defined benefit pension plans.<sup>1548</sup> He adds that DTE has two qualified pension plans that cover eligible DTE employees: one for eligible employees covered by collective bargaining agreements, the DTE Gas Union Plan (Union Plan) and another for all eligible employees of DTE not covered by collective bargaining agreements, the DTE Gas Non-Union Plan (Non-Union Plan), which is a subset of the DTE Energy Retirement Plan.<sup>1549</sup>

Mr. Cooper states that based on the pension funding status on December 31, 2022, DTE is not expected to fund the pension plans in 2023, 2024, or 2025.<sup>1550</sup> He adds that while there is no planned funding of the DTE Gas Union and Non-Union pension trusts, DTE transferred \$50 million of assets related to the Non-Union plan to the DTE Electric's pension trust assets in exchange for cash Employee Benefits consideration in November 2023.<sup>1551</sup> Mr. Cooper states that DTE's pension costs are projected to decrease from \$9.077 million in the historical test year, which includes one-time costs of \$25.811 million related to settlement charges recognized in 2022, to \$0.668 million in the projected test year, such that after adjustments for the portion of pension costs capitalized, the projected pension expense is \$0.336 million.<sup>1552</sup>

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<sup>1547</sup> *Id.*

<sup>1548</sup> 4 Tr 2605.

<sup>1549</sup> *Id.*

<sup>1550</sup> 4 Tr 2608.

<sup>1551</sup> *Id.*

<sup>1552</sup> 4 Tr 2608-2609; Ex. A-13, Sch. C5.10.

Mr. Cooper states that DTE's Other Post-Employment Benefits (OPEB) costs are projected to increase from negative \$38.683 million in the historical test year, which reflects a one-time credit of \$10.784 million related to a change in accounting for the determination of Market Related Value of assets, to a negative \$13.223 million during the projected test year, such that after adjustments for the portion of OPEB costs transferred and capitalized, the net OPEB expense is projected to be negative \$6.255 million.<sup>1553</sup> Mr. Cooper states that the negative OPEB expense is not included in DTE's proposed revenue requirement, and that instead DTE is proposing proposal to continue to defer the projected negative OPEB expense to the accumulated regulatory liability.<sup>1554</sup>

Mr. Coppola states that because of DTE closing the OPEB retiree healthcare plan and establishing a new Retiree VEBA Plan, DTE has been reporting negative expense in recent years, and instead of recording the negative expense against current O&M expense, subsequent to a rate case order, DTE began to record the negative expense to a regulatory liability account.<sup>1555</sup> He adds that as of December 2023, the regulatory deferred liability account balance is \$68,123,000, and that the liability balance through additional negative OPEB expense is forecasted to grow to \$81.3 million by the end of December 2025.<sup>1556</sup> He states that DTE stated that OPEB expense will likely continue to be negative through at least 2030.<sup>1557</sup> He asserts that with the large increase proposed by DTE, it is not fair or reasonable for DTE to continue to defer the OPEB negative expense and not pass through to customers a portion of the deferred regulatory liability

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<sup>1553</sup> 4 Tr 2611; Ex. A-13, Sch. C5.11.

<sup>1554</sup> *Id.*

<sup>1555</sup> 4 Tr 1549-1550.

<sup>1556</sup> 4 Tr 1550; Ex. AG-51.

<sup>1557</sup> *Id.*

balance in this rate case and continuing into the future.<sup>1558</sup> Thus, he proposes that DTE begin to amortize the balance of \$68,136,000 as of December 2023 over a seven-year period and include the resulting amortization expense of \$9,734,000 in the projected test year as a reduction to O&M expense.<sup>1559</sup> Thus, he recommends that DTE's projected O&M expense for the projected test year ending September 2025 be reduced by \$9,734,000.<sup>1560</sup> He adds that in Case No. U-21297, he made a similar proposal in the DTE Electric rate case and the Commission found merit to the proposal and approved it.<sup>1561</sup>

DTE counters that Mr. Coppola's recommendation is based on speculation that negative OPEB expense will continue to be negative for many years to come, and that while DTE currently expects OPEB expense to remain negative through 2030, changes in asset returns and the discount rates could result in positive expense amounts, rendering witness Coppola's proposal inappropriate.<sup>1562</sup> DTE adds that should the Commission adopt Mr. Coppola's amortization proposal, then it should also authorize the continuation of the deferral for OPEB expense incurred in 2024 and future periods to mitigate the uncertainty underlying future expense.<sup>1563</sup>

This PFD agrees with the Attorney General, as the Commission recently did in Case No. U-21297.<sup>1564</sup> Accordingly, this PFD recommends that the Commission adopt

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<sup>1558</sup> *Id.*

<sup>1559</sup> 4 Tr 1550-1551.

<sup>1560</sup> 4 Tr 1551.

<sup>1561</sup> *Id.*

<sup>1562</sup> DTE initial brief, p. 106.

<sup>1563</sup> *Id.*, p. 106-10.

<sup>1564</sup> Case No. U-21297, Order, December 1, 2023, p. 223-224 ("The Commission finds that the ALJ's recommendation [that DTE Electric amortize the regulatory deferred liability account balance over a seven year period] should be adopted. . The Commission also finds persuasive the ALJ's recommendation to authorize continued deferral of OPEB expense incurred in 2023 and in future periods.")

the Attorney General's proposed \$9,734,000 disallowance and authorize the continued deferral for OPEB expense incurred in 2024 and future periods.

Mr. Cooper states that the Employee Savings Plan expense relates to DTE's Employee Savings Plan that allows eligible employees the opportunity to contribute a certain percentage of their annual earnings that DTE matches, with employees hired after DTE's defined benefit pension plans were closed to new hires, generally receiving an additional company contribution of 4.0% of their pay.<sup>1565</sup> He adds that the projected Employee Savings Plan was developed based on the 2022 expense and escalated by the most recent five-year average of the annual increase in DTE's Employee Savings Plan costs of 8.40%.<sup>1566</sup> He states that this results in Employee Savings Plan expense for the projected test year of \$13.166 million compared \$10.368 million in the historical test year.<sup>1567</sup>

Staff does not agree with DTE's increasing the historical amount of 2022.<sup>1568</sup> He asserts that the difference in forfeitures for 2022 is 1.6% compared to the total expense for 2022 of \$16,274,000 and thus immaterial.<sup>1569</sup> He states that Staff updated DTE's expense in 2023 and used a 5-year average annual growth rate (AAGR) from years 2019-2023, which produced a 7.15% AAGR.<sup>1570</sup> He asserts that this resulted in a projection of \$11,483,000, a reduction of \$1,683,000 from DTE's projection of \$13,166,000.<sup>1571</sup>

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<sup>1565</sup> 4 Tr 2614.

<sup>1566</sup> Id.

<sup>1567</sup> Id.

<sup>1568</sup> 4 Tr 1652.

<sup>1569</sup> Id.

<sup>1570</sup> Id.; Ex. S-9.2.

<sup>1571</sup> Id.; Ex. S-9.0.

Mr. Cooper counters that Mr. Rueckert's use of DTE's 2023 as a starting point is improper because DTE capitalized an abnormally high proportion of Employee Savings Plan costs.<sup>1572</sup> He states that he prepared an alternative analysis of DTE's Employee Savings Plan expense which includes a calculation of the impact of the change in the proportion of the total Employee Savings costs capitalized in 2023, which results in Employee Savings Plan expense for the projected test year of \$12.114 million, an increase to the Staff's projected Employee Savings Plan expense of \$631,000.<sup>1573</sup>

This PFD agrees with Staff that the historic amount for 2022 should not be increased as part of this calculation and as such agrees with Staff's update of DTE's expense in 2023 and use of a 5-year average annual growth rate (AAGR) from years 2019-2023 based on DTE's total ESP expense with 1022 unadjusted. Thus, this PFD recommends that the Commission adopt Staff's proposed \$1,683,000 disallowance.

Mr. Cooper states healthcare benefits package consists of medical, dental, and vision benefits for active employees that are projected to increase from \$18.053 million in the historic test year to \$22.041 million, which reflects annual escalations for the adjusted medical plan trend of 5.1% in 2023, 5.0% in 2024, and 4.0% in 2025.<sup>1574</sup> He adds that the adjustment of each year's Active Healthcare costs per employee produces a five-year average cost per employee on a constant dollar basis of \$10,897, which results in a total constant dollar Active Healthcare cost of \$30.609 million and which represents a \$2.134 million increase relative to DTE's Active Healthcare costs in 2022.<sup>1575</sup> He notes that in Case No. U-21297, the Commission declined to adopt the constant dollar normalization

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<sup>1572</sup> 4 Tr 2678.

<sup>1573</sup> Id.; Ex. A-29, Sch. S2.

<sup>1574</sup> 4 Tr 2615-2616; Ex. A-13, Sch. C5.9.

<sup>1575</sup> 4 Tr 2620; Ex. A-13, Sch. C5.9.3.

in this matter, stating that DTE did not sufficiently demonstrate that the “proposed constant dollar normalization will not result in compounded inflationary pressures”.<sup>1576</sup> He asserts that the constant dollar adjustment does not result in compound inflationary pressures and that the constant dollar Active Healthcare costs adjustment merely recasts DTE’s historical Active Healthcare costs for the impact of historical medical cost escalations.<sup>1577</sup>

Mr. Cooper states that the active healthcare expense projections are based on DTE’s 2022 normalized expense as escalated by the adjusted trend factors of 5.10% in 2023, 5.00% in 2024, and 4.00% in 2025.<sup>1578</sup> He adds that the projections of future medical trends relied upon by DTE in recent years has been accurate.<sup>1579</sup>

Ms. Rueckert states that DTE escalated its historic 2022 expense basis by \$1,249,000 using a “constant dollar average” citing volatility, and then further inflated the expense with healthcare trend rates provided by experts at Willis Towers Watson (WTW) adjusted for expected savings from DTE’s Wellness program, resulting in adjusted rates used being 5.10% in 2023, 5.00% in 2024, and 4.00% in 2025.<sup>1580</sup> She asserts that DTE’s “constant dollar average” used to inflate its historic basis is unreasonable, and that this method of historical adjustment has been rejected by the Commission.<sup>1581</sup> She adds that WTW’s generalized healthcare trend are not reflective of DTE’s own expense average annual change, noting that the per-employee Active Healthcare expense has remained relatively flat for the past three years, 2021-2023, and that DTE has not experienced

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<sup>1576</sup> 4 Tr 2623-2624, quoting Case No. U-21297, Order, p. 232.

<sup>1577</sup> 4 Tr 2624.

<sup>1578</sup> 4 Tr 2625; Ex. A-13, Sch. C5.9.1.

<sup>1579</sup> 4 Tr 2628; Ex. A-13, Sch. C5.9.1, Sch. C5.9.2.

<sup>1580</sup> 4 Tr 1652-1653.

<sup>1581</sup> 4 Tr 1653, citing Case U-21297, Order, p. 232.

average annual growth in Active Healthcare near the healthcare trend rate WTW predicts or DTE's adjusted rates.<sup>1582</sup> She states that Staff requested DTE's expense and average annual employee count for 2023, with an average annual growth rate (AAGR) of years 2019-2023 of 0.95%, calculated from the change in Active Healthcare from year to year being applied to all lines of DTE's unadjusted 2023 expense to project it forward.<sup>1583</sup> She concludes that this results in an Active Healthcare expense projection of \$16,721,000, a reduction of \$5,320,000 from DTE's projection of \$22,041,000.<sup>1584</sup>

Mr. Coppola states that the forecasted health care O&M expense to \$22.0 million for the projected test year represents a cumulative increase of approximately 21% from the adjusted actual expense of \$18.1 million in 2022.<sup>1585</sup> He asserts that Mr. Cooper's analysis and calculations that the \$10,897 constant dollar adjusted cost per employee for 2022 is divorced from reality, as this amount is 7.5% higher than the actual cost of \$10,138 for 2022.<sup>1586</sup> Noting that Mr. Cooper is simply compounding inflationary increases on top of inflationary increases over the seven-year period from 2018 to 2025, he asserts that the Commission has repeatedly rejected Mr. Cooper's methodology in previous rate cases for DTE Gas and DTE Electric Company.<sup>1587</sup> Mr. Coppola states that he calculated a forecasted expense of \$17,157,000 for the projected test year, using information obtained from DTE Ex. A-13, Sch. C5.9.3 which has the cost of health care from 2018 to 2022.<sup>1588</sup> He adds that the annualized increase in DTE's costs is 2.4%

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<sup>1582</sup> 4 Tr 1653.

<sup>1583</sup> Id.; Ex. S-9.1 and S-9.3.

<sup>1584</sup> Id.; Ex. S-9.0.

<sup>1585</sup> 4 Tr 1540.

<sup>1586</sup> Id.

<sup>1587</sup> 4 Tr 1540-1541.

<sup>1588</sup> 4 Tr 1541; Ex. AG-47.

between 2018 and 2022, and that the 2.4% average rate of increase already reflects any inflationary increase in costs year over year as actually experienced.<sup>1589</sup> He states that using the 2.4% annual rate of increase and applying it to the actual costs in 2023 of \$16.5 million for subsequent years through the end of the projected test year, he calculated the forecasted expense at \$17,157,000 after allocating a portion of the costs to capital expenditures.<sup>1590</sup> He asserts that this is a reasonable forecast of health care expense for the projected test year based on actual cost trends, and thus, he recommends that the Commission remove the difference of \$4,884,000 from DTE's forecasted test year O&M expense.<sup>1591</sup>

DTE notes the differences between the three approaches to project these expenses; while DTE used its actual 2022 Active Healthcare expense, as normalized for the Constant Dollar adjustment and escalated the adjusted expense for annual escalations provided by Willis Tower Watson (WTW) with reductions for the impact of DTE's Wellness program, while both Staff and the Attorney General DTE's actual 2023 Active Healthcare expense without the Constant Dollar adjustment and escalated based on DTE's actual annual percentage change in its Active Healthcare costs to develop future and escalations of 0.92% by Staff and 2.4% by the Attorney General.<sup>1592</sup> DTE asserts that while both Staff and the Attorney General utilized escalations based on DTE's historical averages, neither of them identified any flaws in WTW's adjusted projections used by DTE.<sup>1593</sup>

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<sup>1589</sup> *Id.*

<sup>1590</sup> *Id.*

<sup>1591</sup> *Id.*

<sup>1592</sup> DTE initial brief, p. 109-110.

<sup>1593</sup> *Id.*, p. 110.

DTE argues that because the price of healthcare services increases each year, it would be unreasonable to predict future Active Healthcare costs based on an average of the historical Active Healthcare costs.<sup>1594</sup> As such, DTE asserts that the only means of producing a starting point for Active Healthcare that is normalized for changes in utilization is to develop a historical average that neutralizes the change in price levels, which is what the Constant Dollar normalization adjustment achieves.<sup>1595</sup> DTE asserts that Staff's and the Attorney General's respective escalation factors (.92% and 2.4%, respectively) are based on DTE's experience, which it asserts is an unreliable predictor of DTE's future Active Healthcare costs because of the inherent volatility in DTE's Active Healthcare costs.<sup>1596</sup>

This PFD agrees with the Attorney General and Staff that DTE unreasonably inflated its historic 2022 expense basis by using a "constant dollar average" and that this method of historical adjustment has been rejected by the Commission. This PFD also recognizes that the Commission has previously agreed that using DTE's AAGR is the most reasonable method for calculating the actual increase in active healthcare expense. See, Case No. U-21297, Order, date, p. 232 ("The Commission finds that DTE Electric insufficiently demonstrated that its proposed constant dollar normalization will not result in compounded inflationary increases. In addition, the Commission agrees with the ALJ that the Staff's approach of using the company's AAGR, rather than the national average of increase, is the most reasonable method for calculating the actual increase in active health care expense."). This PFD recommends that the Commission adopt the

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<sup>1594</sup> Id., p. 112.

<sup>1595</sup> Id.

<sup>1596</sup> Id., p. 115,116.

disallowance proposed by the Attorney General (\$4,884,000) as its proposed escalation of 2.4% is slightly more reasonable than Staff's 0.92%, about which Staff escalation DTE says unreasonably presumes that DTE's Active Healthcare costs will escalate by less than a third of the overall price inflation measured by the CPI of 3.2% unreasonable."<sup>1597</sup>

### **Employee Compensation**

DTE states that its incentive compensation plan consists of two short-term incentive plans—the Annual Incentive Plan (AIP) and the Rewarding Employees Plan (REP)—and one multiple year plan known as the Long-Term Incentive Plan (LTIP) that is available to all managers and above and up to 10% of other eligible non-represented exempt employees.<sup>1598</sup>

Mr. Cooper states that total annual compensation for all non-represented employees has two primary components: base and variable pay, with base pay being reviewed annually and adjusted (if appropriate) based on the position relative to what the external market pays for similar positions and individual performance and with variable pay based on the achievement of DTE, as well as departmental and individual results.<sup>1599</sup>

Mr. Cooper states that the projected incentive compensation expense of \$18.511 million should be included in the revenue requirement and adopted by the Commission in this proceeding.<sup>1600</sup> He adds that his proposal to include all DTE's projected incentive compensation expense, exclusive of the portion related to the top five executive officers, is based on the prevalence of incentive compensation programs and the resultant need for DTE to have total compensation programs that enable it to be competitive with other

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<sup>1597</sup> Id., p. 115.

<sup>1598</sup> DTE initial brief, p. 118.

<sup>1599</sup> 4 Tr 2636.

<sup>1600</sup> 4 Tr 2644.

employers.<sup>1601</sup> He states that the DTE's existing total cash compensation is in line with the market, as is the total compensation for its executives, and that, in the absence of the incentive compensation programs, total cash compensation for DTE's employees would be 12.2% less than the market medians.<sup>1602</sup>

Mr. Cooper states that the Commission has indicated in its recent Orders that recognition of incentive compensation expense in a company's revenue requirement was dependent on a showing that the incentive compensation programs provided benefits to customers in excess of the expense.<sup>1603</sup> He asserts that DTE has performed a comprehensive analysis of the customer benefits that would be derived from the achievement of the financial and operating metrics included in DTE's short and long-term incentive plans relative to their costs, which demonstrates that the expected aggregate benefits of \$19.075 million exceeds the incentive compensation expense of \$18.232 million by \$0.844 million.<sup>1604</sup>

Regarding DTE's projection of \$18,511,000 for the projected test-year ending September 30, 2025, with \$12,147,000 related to the achievement of financial performance measures, and \$6,364,000 related to non-financial operating objectives, Ms. McMillan-Sepkoski asserts that Commission decisions to exclude incentive compensation related to financial measures from the revenue requirement in preceding rate cases are founded on two premises: a) that incentive compensation plans that were tied to company earnings and cash flow were financial considerations that largely benefited shareholders and should not be paid for by ratepayers, and b) that long-term

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<sup>1601</sup> 4 Tr 2645.

<sup>1602</sup> Id.; Ex. A-19, Sch. 11.

<sup>1603</sup> 4 Tr 2658.

<sup>1604</sup> Id.; Ex. A-19, Sch. 15.

incentive compensation is tied closely to company earnings and cashflow that benefits the shareholders more than the ratepayers.<sup>1605</sup> She adds that the Commission has excluded the capitalized and O&M financial performance measures from the revenue requirement on the basis that shareholders specifically benefit from financial performance measures such as return on equity and cash flow, whereas ratepayers specifically benefit from measures related to reliability and customer satisfaction.<sup>1606</sup> She states that Staff recommends the inclusion of the EICP for non-financial performance measures for the amount of \$6,364,000 is reasonable but that the \$12,147,000 related to the achievement of financial performance measures should be disallowed.<sup>1607</sup>

Noting that DTE states that LTIP is awarded with Restricted Stock or performance shares, with the amount of compensation in the form of Restricted Stock included in the revenue requirement is \$2,017,000, Ms. McMillan-Sepkoski asserts that the Commission has repeatedly disallowed any portion of compensation related to financial measures to be included in the revenue requirement.<sup>1608</sup> As such, she recommends a disallowance of Restricted Stock in the amount of \$2,017,000.<sup>1609</sup>

Ms. McMillan-Sepkoski states that Staff disagrees with DTE's request that the Incentive Compensation Mechanism should include the financial metrics portion of the incentive compensation and that the deferral should cover payout beyond the 100% target level, which means that the amount could go as high as 175% of target.<sup>1610</sup> She asserts

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<sup>1605</sup> 4 Tr 1699; Ex. S-8.0; Case No. U14347, Opinion and Order, December 22, 2005, p 35; Case No. U-17735, Opinion and Order, November 19, 2015, p 78.

<sup>1606</sup> 4 Tr 1700.

<sup>1607</sup> 4 Tr 1701; Ex. S-8.0.

<sup>1608</sup> 4 Tr 1701, citing Case No. U-20561, Order, May 8, 2020, pgs. 202-203, Case No. U-20836, Order, November 18, 2022, pgs. 302-303, and Case No. U-21297, Order, December 1, 2023, p. 238.

<sup>1609</sup> 4 Tr 1702.

<sup>1610</sup> 4 Tr 1702.

that the Commission has consistently disallowed recovery in rates for financially based incentive compensation, and thus, the incentive compensation mechanism should not include financially based incentive compensation in the deferral.<sup>1611</sup> She adds that if DTE were to be approved to include in the incentive compensation deferral mechanism payouts at up to 175% of target, this would mean that the total compensation paid to employees would be above market median, which could result in unnecessary and excessive rates for ratepayers in the future.<sup>1612</sup> She asserts that the Commission's duty is to set reasonable rates, and thus, the Commission was correct in setting the maximum target level of 100% for the deferred incentive compensation mechanism amounts to be recovered in re DTE Gas MPSC Case No. U-20940, December 9, 2021 Order, p. 163.<sup>1613</sup> As such, she recommends to the ALJ and the Commission that incentive compensation included in the deferral mechanism maximum at 100% target level is reasonable.<sup>1614</sup>

DTE notes that Staff's proposed exclusion of \$14.164 million represents \$12.147 million of expense based on the supposed financial measures of the two short-term incentive programs and the LTIP.<sup>1615</sup> DTE asserts that Staff's \$12.147 million exclusion appears to be premised exclusively on the Commission's traditional practice of excluding incentive compensation expense related to financial performance measures, as the Commission has taken the view that these measures largely benefit shareholders and should not be borne by ratepayers.<sup>1616</sup> DTE asserts that Ms. McMillan Sepkoski's proposal fails to assess the overall reasonableness of DTE's total compensation

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<sup>1611</sup> *Id.*

<sup>1612</sup> 4 Tr 1703.

<sup>1613</sup> *Id.*

<sup>1614</sup> *Id.*

<sup>1615</sup> DTE initial brief, p. 119.

<sup>1616</sup>

practices.<sup>1617</sup> Moreover, DTE argues that the fact that the LTIP is based on DTE Energy common stock does not mean that LTIP awards are financial measures, asserting that the amount of compensation delivered through the LTIP is not dependent on DTE Energy's stock price.<sup>1618</sup>

Mr. Coppola states that DTE proposes to recover \$1,774,000 of amortization expense in the projected test year related the amount of incentive compensation recorded in a regulatory asset account, while he proposes an amortization expense amount of \$717,000, which is \$1,057,000 lower than DTE's proposed amount.<sup>1619</sup> He asserts that the regulatory asset deferred balance that should be included in working capital is \$3,227,000, making DTE's working capital balance of \$13,310,000 overstated by \$10,083,000, and recommends that the Commission remove the \$10,083,000 from DTE's forecasted working balance amount for the projected test year. He also recommends that the Commission remove the \$1,057,000 of excess amortization expense from the Company's O&M expense for the projected test year.<sup>1620</sup> DTE counters that Mr. Coppola's calculation of the working capital balance is flawed and thus unsupported. As discussed, *supra*, this PFD agreed and recommended that the Commission reject that proposed disallowance. Similarly, this PFD recommends that the Commission reject the Attorney General's \$1,057,000 amortization expense disallowance.

Mr. Coppola asserts that the three incentive plans are too heavily skewed toward measures that directly benefit shareholders and not customers, and that the customer benefits presented by DTE are based on a faulty premise of historical cost savings and

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<sup>1617</sup> Id. Citation omitted.

<sup>1618</sup> 4 Tr 2669.

<sup>1619</sup> 4 Tr 1542-1543; Ex. AG-21.

<sup>1620</sup> 4 Tr 1543.

an expectation that future targets of performance will be achieved.<sup>1621</sup> He states that with regard to the AIP and REP, nearly half of the incentive payout at target level relates to DTE and its parent, DTE Energy, achieving net income, earnings per share, and cash flow goals, and that there is no direct relationship to customer benefits.<sup>1622</sup> He asserts that it is even more inappropriate to charge customers for incentive pay costs related to achieving DTE Energy earnings per share since those earnings include earnings from the electric and non-utility businesses of DTE Energy, and that the Commission should not allow recovery of incentive payments related to these financial goals.<sup>1623</sup>

Mr. Coppola states that as to the Customer Satisfaction measures, this category the benefits achieved are far less than the costs as measured by DTE.<sup>1624</sup> He adds that with regard to the Employee Engagement category, the measures do not rise to the level of being measures that are visible to customers nor do they create direct customer benefits as they are primarily internal goals related to employee satisfaction and deployment of safe practices in the workplace.<sup>1625</sup> He states that as to the Operating Excellence category, the measures are basic operating goals which have no direct visibility to customers.<sup>1626</sup>

Mr. Coppola states that the LTIP is a plan strictly designed to induce management to create shareholder value, as it is weighted heavily (80%) on total shareholder return for DTE Gas employees and 80% in the case of the LLC employees, which is stock price appreciation and dividends paid over a period of time, and which has nothing to do with

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<sup>1621</sup> 4 Tr 1545.

<sup>1622</sup> 4 Tr 1545.

<sup>1623</sup> *Id.*

<sup>1624</sup> 4 Tr 1546; Ex. A-19, Sch. 15.

<sup>1625</sup> *Id.*

<sup>1626</sup> *Id.*

creating direct benefits for DTE Gas customers and everything to do with creating value for DTE Energy shareholders.<sup>1627</sup>

Regarding DTE purporting to show that the expected operating and financial cost savings in 2023 of \$21.2 million will exceed the incentive plan payments by \$2.8 million, Mr. Coppola counters that actual results are doubtful.<sup>1628</sup> He adds that DTE's claim that it has realized cost savings by preventing higher interest rates by managing its credit ratings is unconvincing, and that DTE has generally fallen short of its performance targets in the Customer Satisfaction and Employee Engagement areas.<sup>1629</sup> Noting that DTE has included in its O&M expense for the projected test year, which includes \$12.1 million pertaining to financial measures, he recommends that the Commission remove the entire \$12.1 million related to financial performance measures.<sup>1630</sup>

Regarding the portion of incentive compensation relating to operating measures, Mr. Coppola states that DTE has not made a sufficiently compelling case to justify recovery of these costs.<sup>1631</sup> Cognizant of the fact that the Commission has recently allowed recovery of a portion of the short-term incentive pay related to operating performance measures for DTE Gas, DTE Electric, and Consumers Energy, Mr. Coppola recommends that the Commission allow recovery of only 55% of the incentive compensation expense that DTE has identified pertaining to operating performance measures, as 55% represents the percentage of performance measures that have been achieved at target level or higher over the past five years from 2019 to 2023.<sup>1632</sup> He

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<sup>1627</sup> Id.

<sup>1628</sup> 4 Tr 1547.

<sup>1629</sup> Id.

<sup>1630</sup> 4 Tr 1548.

<sup>1631</sup> 4 Tr 1548.

<sup>1632</sup> Id.; Ex. 49.

asserts that in calculating the incentive compensation expense in this rate case, DTE has assumed in that it will achieve the target level for all operating performance measures, while noting that in the last five years of actual performance results show that DTE was able to achieve target level performance only 55% of the time with certain years as low as 36% and some years as high as 89%.<sup>1633</sup> As DTE calculated \$6.4 million of incentive compensation related to operating performance measures, which amount he asserts assumes that 100% of the operating measures will be achieved at the 100% target level, he recommends that the Commission allow recovery of only 55% of the \$6.4 million, or \$3.5 million, and disallow the remaining \$2.9 million.<sup>1634</sup>

Noting Mr. Coppola's proposed related to financial measures are based on Mr. Coppola's claims that the plans are too heavily skewed toward financial measures that only directly benefit shareholders, DTE counters that this is a summary conclusion that earnings and cashflow measures have no direct relationship to customer benefits.<sup>1635</sup> DTE adds that this conclusion also ignores the multiple customer benefits related to the maintenance of DTE's current debt ratings, avoided increased interest costs, and the operating and capital cost savings enabled by an organizational emphasis on operating efficiencies that produce improved earnings and cash flow and the advantage of DTE's ready access to capital markets.<sup>1636</sup>

Regarding Mr. Coppola's proposal to exclude 45% of the incentive compensation expense related to Operating measures, Mr. Cooper argues that Mr. Coppola's analysis of the proportion of measures that were at Target or Above is flawed because it fails to

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<sup>1633</sup> Id.

<sup>1634</sup> Id.

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recognize that while certain measures may produce results that are less than Target, other measures can produce results that are greater than Target.<sup>1637</sup> He adds that even those measures where actual performance was less than Target can still generate payouts if the actual performance was higher than the Threshold level.<sup>1638</sup> He states that Mr. Coppola's exclusive reliance on the achievement of performance relative to Target levels fails to recognize the gradients of performance between Threshold and Maximum performance levels that are the basis for actual payouts.<sup>1639</sup>

Mr. Fitzhenry states that all three incentive compensation programs contain measures that are impacted by financial performance, including goals such as realizing DTE's operating earnings objectives, cash from operations, and operating earnings per share with the amount associated with financial performance being \$12.0 million.<sup>1640</sup> He asserts that Incentive Compensation Programs that are designed to align the interests of employees with shareholders should be paid for by shareholders, and to the extent incentive compensation reflects customer-directed goals such as service reliability, and/or employee safety, only then is it fair and reasonable to recover the costs of those programs from ratepayers if the operational performance metrics are actually achieved.<sup>1641</sup> He adds that the Commission previously rejected the inclusion of incentive compensation related to financial performance in the revenue requirement.<sup>1642</sup> He states that the costs associated with financial performance outweigh the benefits to customers

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<sup>1637</sup> 4 Tr 2675

<sup>1638</sup> Id.

<sup>1639</sup> 4 Tr 2676.

<sup>1640</sup> 4 Tr 1326. Citation omitted.

<sup>1641</sup> Id.

<sup>1642</sup> 4 Tr 1326-1327, citing Case No. U-20561, Order, May 8, 2020, p. 17 and Case No. U-20836, Order, November 18, 2022, p. 301.

in five out of six metrics, and cost \$12.0 million but only ostensibly provide \$6.1 million in benefits to customers.<sup>1643</sup> Thus, he recommends the Commission reject DTE's proposal to include \$12.0 million of incentive compensation expense that is associated with financial performance in the revenue requirement adopted in this case.<sup>1644</sup>

This PFD agrees with Staff, the Attorney General and ABATE that the inclusion of the EICP for financial performance measures in the amount of \$12,147,000 should be disallowed. As Staff, the Attorney General and ABATE assert and as DTE acknowledges, the Commission has consistently disallowed recovery in rates for financially based incentive compensation. See, e.g., Case No. U-20940, Order, December 9, 2021, p. 162-163.

The Commission finds that the ALJ properly recommended the disallowance of recovery for incentive compensation tied to financial metrics. In Case No. U-14347, the Commission held that the utilities have the burden to demonstrate how incentive programs benefit ratepayers and reiterated that the benefits "at a minimum, will be commensurate with the programs' costs." The company has not demonstrated, on this record, actual benefits that would accrue to ratepayers from the recovery of incentive compensation tied to financial metrics. 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.<sup>1645</sup>

Thus, this PFD recommends that the Commission adopt this \$12,147,000 disallowance.

Similarly, this PFD agrees with Staff and the Attorney General that the LTIP which awards with Restricted Stock, which DTE includes in the revenue requirement in the amount of \$2,017,000 should be disallowed. Again, the Commission has disallowed Restricted Stock compensation related to financial measures to be included in the

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<sup>1643</sup> 4 Tr 1327; Ex. A-19, Sch. I-5.

<sup>1644</sup> *Id.*

<sup>1645</sup> Citation omitted.

revenue requirement.<sup>1646</sup> See, e.g., Case No. U-21297, Order, December 1, 2023, p. 238-239

The Staff also proposes a disallowance of \$6.53 million for restricted stock because it is “based on DTE Energy Company stock prices, which is a financial measure used by the Company to determine the amount of the award. Restricted Stock is considered as a reward to employees for assisting the Company in reaching its financial performance goals.” The Commission agrees and finds that the Staff’s proposed disallowance should be approved.<sup>1647</sup>

As such, this PFD recommends that the Commission adopt this disallowance in the amount of \$2,017,000.

Regarding recovery of incentive compensation for operation metrics, this PFD agrees with the Attorney General that DTE should not recover as if it will achieve all operating measures at the 100% target level. This PFD notes that the Commission recently agreed. See, Case No. U-20940, Order, December 9, 2021, p. 163.

The Commission further notes its concern regarding the current approach to recovery of incentive compensation for operational metrics. The company’s request is for recovery of the full incentive compensation amount, assuming 100% target level performance in each of the operational measures. However, as demonstrated by the Attorney General, the “last five years of actual performance results show that the Company was able to achieve target level performance only 20% of the time with certain years as low as 8% and some years as high as 31%.” Therefore, the Commission is persuaded that DTE Gas should not recover as if it will achieve all operating measures at the 100% target level. Instead, the Commission adopts the proposal from the Attorney General to allow recovery of 20% of the incentive compensation for meeting operational metrics.<sup>1648</sup>

Thus, this PFD recommends that the Commission adopt this disallowance of \$2,864,000.

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<sup>1646</sup> 4 Tr 1701, citing Case No. U-20561, Order, May 8, 2020, pgs. 202-203, Case No. U-20836, Order, November 18, 2022, pgs. 302-303, and Case No. U-21297, Order, December 1, 2023, p. 238.

<sup>1647</sup> Citation omitted.

<sup>1648</sup> Citation omitted.

Mr. Coppola states that in response to discovery, DTE indicates that the Voluntary Separation Incentive Plan (VSIP) was a separation plan offered to 422 DTE Gas employees and 1,622 DTE Corporate Services employees in an effort to realign the workforce to support the changing nature of DTE's work, including an increased focus on infrastructure investments, cybersecurity, and the clean energy transition.<sup>1649</sup> He adds that DTE states that of those employees to whom VSIP was offered, 42 DTE Gas employees and 249 Corporate Services employees accepted the separation plan, resulting in up to \$6.3 million of labor cost savings in 2025, based on preliminary estimates, which \$6.3 million does not include employee benefit savings from lower active health care costs, 401k plan matching, and other benefits.<sup>1650</sup> He states that conservatively, he has included only half, or \$3.2 million, of the currently estimated labor cost savings of \$6.3 million as a reduction to the O&M expense for the projected test year, and thus recommends that the Commission accept this additional adjustment of \$3.2 million to the forecasted O&M expense for the projected test year.<sup>1651</sup>

DTE counters that this reduction is inappropriate as it is premature to include any VSIP savings in DTE's revenue requirement at this time, because DTE continues to assess the need to fill key vacated positions, and any estimated savings will continue to evolve as these positions are filled.<sup>1652</sup> DTE asserts that it is more prudent to wait until any savings are actually incurred, which can then be reflected in DTE's future revenue requirements.<sup>1653</sup> DTE adds that it would be unreasonable to include a reduction to DTE's

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<sup>1649</sup> 4 Tr 1533; Ex. AG-46.

<sup>1650</sup> 4 Tr 1533-1534.

<sup>1651</sup> 4 Tr 1534.

<sup>1652</sup> DTE initial brief, p. 122.

<sup>1653</sup> *Id.*

total O&M expense of estimated savings without any simultaneous recognition of the \$8 million of costs incurred by DTE.<sup>1654</sup> DTE argues that should the Commission believe that some savings should be reflected, Mr. Coppola inappropriately used the estimated 2025 savings of \$6.3 million and attributed it all to the projected test year, asserting that the \$6.3 million was for the entire 2025 calendar year, so this amount should be prorated for the nine months ending September 30, 2025.<sup>1655</sup> DTE states that the prorated expense is accordingly only \$4.7 million, such that applying Mr. Coppola's formula of including half of such costs would result in an O&M reduction of \$2.350 million.<sup>1656</sup>

This PFD agrees with the Attorney General that these 2024 cost reductions initiated by DTE should be recognized as a reduction to the O&M expense for the projected test year. This PFD agrees with DTE that Mr. Coppola's proposed disallowance should be prorated for the nine months ending September 30, 2025. Thus, this PFD recommends that the Commission adopt the attorney General's disallowance of \$2.35 million.

### **Uncollectible Expense**

Mr. Sparks states that uncollectible expense is the income statement impact of the portion of accounts receivable that is considered uncollectible from customers who used gas service.<sup>1657</sup> He adds that to be consistent with prior rate making approvals, in this case DTE is utilizing a historical three-year average of actual net write-offs plus direct expense for 2020-2022 and adjusted for revenue growth, resulting in a \$35.149 million of

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<sup>1654</sup> Id.

<sup>1655</sup> Id.

<sup>1656</sup> Id.

<sup>1657</sup> Id.

uncollectible expense.<sup>1658</sup> He states that in this case, DTE is adopting Staff's methodology from the last rate case No. U-20940.<sup>1659</sup>

Mr. Rueckert states that Staff does not support DTE's projected uncollectible accounts expense, asserting that while DTE's methodology is consistent with Staff's direct write off method, the revenue amount used is excessive.<sup>1660</sup> He adds that Energy Optimization Revenue should be excluded as it is not included in this general rate case.<sup>1661</sup> He recommends the use of total current revenue projected test year billing determinants at the current base rates.<sup>1662</sup> He states that Staff used the direct write-off method applied to total current revenue, resulting in an uncollectible expense projection of \$20,679,000, which is a downward adjustment of \$14,470,000 from DTE's request of \$35,149,000.<sup>1663</sup>

Regarding DTE's expense for uncollectible gas accounts, Mr. Coppola states that using the most recent revenues and net charge-offs for 2023, he calculated uncollectible accounts expense of \$26,018,000 for the projected test year.<sup>1664</sup> He adds that having added amounts not included in the test year revenues results in total uncollectible accounts expense of \$26,018,000, which is lower than DTE's forecast of \$35,149,000 by \$9,131,000.<sup>1665</sup> Thus, he recommends that the Commission adopt his forecast of

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<sup>1658</sup> S Tr 21; Ex. A-13, Sch. C5.7.

<sup>1659</sup> Id.

<sup>1660</sup> 4 Tr 1650.

<sup>1661</sup> Id.

<sup>1662</sup> Id.; Ex. S-6, Sch. F2, p. 1.

<sup>1663</sup> Id.; Ex. S-9.5.

<sup>1664</sup> 4 Tr 1529; Ex. AG-42.

<sup>1665</sup> 4 Tr 1529.

\$26,018,000 for uncollectible accounts expense and reduce DTE's O&M expense by \$9,131,000.<sup>1666</sup>

DTE disagrees with Staff for several reasons. DTE asserts that if new rates are approved, uncollectible expense will be impacted by these new rates, in addition to projected billing determinates.<sup>1667</sup> DTE argues that using the rates currently in place is unjust, as it denies DTE a reasonable chance to recover the uncollectible costs that it will be incurring.<sup>1668</sup> DTE states that until changes are made to the EWR allowing recovery of EWR uncollectible expense, denying DTE a chance to recover those costs would be unjust and unreasonable.<sup>1669</sup> DTE asserts that there is a mismatch between the revenues used by Staff to calculate the write-off percentage and the revenues used to calculate uncollectible expense, with the historical revenue used to calculate write-offs as a percentage of revenue being on a different basis than the \$1.677 billion used to calculate uncollectible expense.<sup>1670</sup> DTE adds that if the Commission were to approve Staff's methodology, DTE recommends two adjustments to Staff's uncollectible expense calculation. First, DTE has adjusted historical revenue to also exclude any revenue Staff has excluded from projected revenue, which adjustment increases Staff's uncollectible calculation by \$3.965 million.<sup>1671</sup> Second, DTE proposes to use Staff's proposed revenue, as opposed to present revenue, which proposed revenue drives an additional \$0.984 million increase to Staff's uncollectible expense.<sup>1672</sup>

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<sup>1666</sup> Id.

<sup>1667</sup> DTE initial brief, p. 125.

<sup>1668</sup> Id.

<sup>1669</sup> Id., p. 126.

<sup>1670</sup> Id.

<sup>1671</sup> Id., p. 127.

<sup>1672</sup> Id.

In its brief, Staff argues that future rates projected by DTE prior to audit and Commission approval are speculative.<sup>1673</sup> Staff asserts that its method is more accurate because it uses the current known rates in its projection, and that DTE's use of proposed rates creates the highest projection possible to be recovered from rate payers.<sup>1674</sup>

This PFD agrees with Staff and the Attorney General that DTE's projected uncollectible expense is inflated. This PFD finds that Staff's calculation is the most accurate and reasonable estimate as it uses the current known rates in its projection. Thus, this PFD recommends that the Commission adopt Staff's proposed disallowance in the amount of \$14,470,000.

#### **Lost and Unaccounted for and Company Use Gas, Gas-in-Kind**

Mr. Bence states that Lost and Unaccounted For (LAUF) gas is the difference between booked sources of gas and booked disposition of gas.<sup>1675</sup> He adds that sources of gas greater than the disposition of gas for a pipeline system represent losses, and sources of gas less than the disposition of gas represent gains.<sup>1676</sup>

Mr. Bence states that DTE Gas is supporting 5.4 Bcf of LAUF gas for the projected test year, which is based on the five-year January 1, 2018 to December 31, 2022 average and is higher than the 4.6 Bcf filed in Case No. U-20940.<sup>1677</sup> He adds that to minimize the impact of swings in the unaccounted-for nature of LAUF gas, the Commission and Staff have supported the use of a five-year average in DTE Gas's last six fully litigated general

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<sup>1673</sup> Staff initial brief, p. 63.

<sup>1674</sup> *Id.*

<sup>1675</sup> 4 Tr 2061.

<sup>1676</sup> *Id.*

<sup>1677</sup> 4 Tr 2064; Ex. A-15, Sch. E9.

rate cases. (Cases Nos. U-15985, U-13898, U-10150, U-17999, U-18999, and U-20940).<sup>1678</sup>

Mr. Bence states that Company Use volume is predominantly fuel that is used to operate and maintain DTE Gas's transmission and storage facilities, with compressor fuel comprising over 70% of the total Company Use volume.<sup>1679</sup> He adds that Projected Company Use is 4.5 Bcf for the projected test year.<sup>1680</sup> He states that based on 4.5 Bcf Company Use volumes and 786.2 Bcf projected total throughput volumes, the average Company use is 0.57% of total throughput gas used by DTE.<sup>1681</sup>

Mr. Bence states that design peak day volume (2.5 Bcf, from GCR plan U-21271, is determined annually for gas cost recovery purposes to ensure DTE Gas's retail customer (GCR, GCC and end-user transportation) markets can be physically served even with the coldest historical temperatures that have been experienced in its service areas.<sup>1682</sup>

Mr. Decker states that Gas in Kind (GIK) is gas (expressed as a percentage of throughput) that is supplied by customers to offset Company Use gas and Lost and Unaccounted For (LAUF) gas.<sup>1683</sup> He recommends maintaining GIK rates that were approved by the Commission in Case Nos. U-18999 and U-20940 and utilized in the settlement agreement for Case No. U-20642: ST, LT, XLT 1.41%; XXL 1.00%; Off System 1.00%.<sup>1684</sup> He adds that these GIK rates support the current off-system and end-

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<sup>1678</sup> Id.

<sup>1679</sup> 4 Tr 2069.

<sup>1680</sup> 4 Tr 2070; Ex. A-15, Sch. E11.

<sup>1681</sup> 4 Tr 2071; Ex. A-15, Sch. E11, Sch. E14.

<sup>1682</sup> 4 Tr 2072.

<sup>1683</sup> 2 Tr 40.

<sup>1684</sup> 2 Tr 41, Table 1; Ex. A-15, Sch. E14.

use transportation competitive business environment without additional risk to load and revenue loss, and that these GIK rates provide a contribution to the recovery of LAUF for all other rate classes including Commission-approved special contracts.<sup>1685</sup> He states that the GIK percentage for the GCR/GCC sales rate customers is equivalent to 2.09% and amortized in base rates for these customers.<sup>1686</sup>

Mr. Krause states that Staff recalculated Lost and Unaccounted For (LAUF) and Company Use (CU) gas based on changes in Staff's projections.<sup>1687</sup> He adds that Staff recommends LAUF of \$22,151,000 and CU of \$18,310,000.<sup>1688</sup>

Mr. Coppola states that, regarding Company use and LAUF gas expense, DTE projected these costs partially based upon NYMEX gas futures prices for the projected test year, and that since then, gas costs have declined substantially.<sup>1689</sup> He adds that DTE provided updated forecasted gas prices for the projected test year as of February 2024, which shows that NYMEX gas prices have fallen from \$3.831 per MMBTU assumed in the rate case filing to \$3.123 per MMBTU, and that based on this information, DTE calculated a change in the cost of gas of \$0.28 per Mcf to reflect a revised cost of gas rate of \$4.10 per Mcf. He states that he applied the reduction in the cost of gas rate to the volumes forecasted by DTE to reduce the O&M expense for both Company Use Gas and LAUF Gas by \$2.8 million.<sup>1690</sup>

Mr. Coppola states that he reduced the LAUF volume by 529 MMcf, which represents 9.8% of the LAUF gas volume forecasted by DTE for the projected test

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<sup>1685</sup> Id.

<sup>1686</sup> 2 Tr 42; Ex. A-15, Sch. E14.

<sup>1687</sup> 4 Tr 1721.

<sup>1688</sup> 4 Tr 1722.

<sup>1689</sup> 4 Tr 1526.

<sup>1690</sup> 4 Tr 1526; Ex. AG-40.

year.<sup>1691</sup> He adds that many of DTE's witnesses discuss programs that should result in lower LAUF gas volumes, and that given the significant expenditures by DTE for infrastructure replacement and other programs, it is reasonable to expect progressively lower LAUF gas volumes in the coming years.<sup>1692</sup> Noting that DTE has a goal to reduce greenhouse gas emissions, which includes methane emissions, to net zero by 2050 and reduce greenhouse gas emissions by customers by 35% by 2050, he calculates a 9.8% likely savings in LAUF gas volumes in the projected test year.<sup>1693</sup> He adds that the 529 MMcf adjustment multiplied by DTE's revised \$4.10 per Mcf cost of gas rate results in lower LAUF gas expense of \$2.2 million.<sup>1694</sup> Thus, he recommend that the Commission reduce the expense for Company Gas Use and LAUF gas from DTE's forecasted amount of \$43,209,000 to \$38,276,000 for a total expense reduction of \$4,932,000 for the projected test year.<sup>1695</sup>

Mr. Bence counters that he disagrees with Mr. Coppola's proposal to reduce the amount of LAUF volume by 529 MMcf, asserting that although leaks are a component of LAUF, there are other components that will not be impacted by DTE's net zero goal.<sup>1696</sup> He adds that despite DTE's stated net zero goal, there is a possibility that leaks will never be fully eliminated.<sup>1697</sup> He states that since DTE has been actively implementing its Gas Renewal Program for many years now, the results of this program will be captured in the five-year average methodology utilized by DTE, asserting that using a five-year average

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<sup>1691</sup> Id.

<sup>1692</sup> 4 Tr 1527.

<sup>1693</sup> Id.

<sup>1694</sup> Id.

<sup>1695</sup> 4 Tr 1528.

<sup>1696</sup> 4 Tr 2076.

<sup>1697</sup> Id.

minimizes the impact of swings resulting from the unaccounted for nature of LAUF and is a reasonable and prudent methodology.<sup>1698</sup>

In its brief, the Attorney General states that DTE indicated that the historical five-year average of 5.4 Bcf of LAUF gas volumes includes only the actual historical average volumes with any consideration for further reductions that might come about from DTE's net-zero emission goal.

This PFD agrees with the Attorney General's approach to reduce the LAUF volume by 529 MMcf, as it is reasonable to expect progressively lower LAUF gas volumes in the coming years. As such, this PFD recommends that the Commission adopt the Attorney General's proposed disallowance of \$4,932,000.

### **Property and Other Taxes**

DTE seeks to recover \$114.1 million of property tax expense for the projected test period.<sup>1699</sup> In addition, DTE projects \$16.9 million in Other Tax Expense for the projected test year, made up of payroll taxes of \$13.6 million and Public Utility Assessment fees of \$3.3 million.<sup>1700</sup>

Mr. Coppola identified the adjustments to be made to DTE's proposed capital expenditures and asserts that those reductions lower the amount of property tax expense that DTE will incur during the projected test year.<sup>1701</sup> He states that he calculated a reduction in property tax expense of \$5,019,000 million and that he recommends that the

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<sup>1698</sup> Id.

<sup>1699</sup> 4 Tr 2382; Ex. A-13, Sch. C1.

<sup>1700</sup> 4 Tr 2383; Ex. A-13, Sch. C7.

<sup>1701</sup> 4 Tr 1566.

Commission reduce DTE's property tax expense by this amount for the projected test year.<sup>1702</sup>

DTE counters that not all capital expenditures are subject to property tax in the same way, asserting that plant additions and changes in CWIP are each taxed differently, and removal costs are not subject to property tax at all.<sup>1703</sup> DTE argues that Mr. Coppola's methodology fails to distinguish these components of the capital expenditure reduction so they can be properly accounted for.<sup>1704</sup> DTE asserts that Mr. Coppola incorrectly assumes that all proposed capital expenditure reductions will reduce the property tax liability immediately, while noting that the property tax liability for any given year is based on the taxable value of property on December 31 of the previous year, so any disallowances of capital will not impact the property tax liability until the subsequent calendar year.<sup>1705</sup> DTE states that Mr. Coppola fails to calculate true cash value, which should be calculated by multiplying the appropriate State Tax Commission (STC) multiplier by the cost of the property.<sup>1706</sup> DTE also argues that Mr. Coppola's methodology fails to appropriately parse out projected test period property tax expense across the 2024 and 2025 calendar year.<sup>1707</sup>

Staff also proposes a reduction of \$58,000 for property taxes for the projected test year.<sup>1708</sup> DTE counters that Staff failed to distinguish the components of the capital expenditure reduction (plant additions, changes in CWIP, and removal costs), exclude

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<sup>1702</sup> Id.; Ex. AG-20.

<sup>1703</sup> DTE initial brief, p. 131.

<sup>1704</sup> Id.

<sup>1705</sup> Id.

<sup>1706</sup> Id.

<sup>1707</sup> Id.

<sup>1708</sup> 4 Tr 1746.

removal costs from the calculation, and apply the correct STC multiplier to CWIP.<sup>1709</sup> In addition, Staff did not utilize the monthly capital expenditure projections in its attempt to consider the subsequent year impact of capital expenditure disallowances.<sup>1710</sup>

This PFD agrees with DTE that the Attorney General's and Staff's calculations are overly broad and general, and thus are unreasonable and unsupported. Thus, this PFD recommends that the Commission reject the Attorney General's and Staff's proposed disallowances.

Mr. Coppola states that DTE shows \$4.7 million of Allowance for Funds Used During Construction (AFUDC) pertaining to several project costs included in construction work in process for large projects that will not be in-service before the end of the projected test year.<sup>1711</sup> He states that included on this list of projects are four projects for which he recommends that the Commission remove the capital expenditures from construction work in process and rate base. he recommends that the Commission remove the capital expenditures from construction work in process and rate base for four projects that will not be in-service before the end of the projected test year: 1) the Fort Street Main Replacement project, 2) the Austin-Detroit A&B Lines, 3) Oakland Resiliency (CMS Line 2700) project, and (40) the Belle River Detroit Loop Line.<sup>1712</sup> He adds that to avoid a duplication of reduction in the revenue requirement, he removed \$2,210,000 of AFUDC from his calculation of the revenue requirement in this rate case.<sup>1713</sup>

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<sup>1709</sup> DTE initial brief, p. 132.

<sup>1710</sup> *Id.*

<sup>1711</sup> 4 Tr 1567.

<sup>1712</sup> 4 Tr 1567; Ex. A-13, Sch. C11.

<sup>1713</sup> *Id.*

This PFD agrees that an adjustment should be made to the AFUDC for projects that will not be in-service before the end of the projected test year. However, as discussed, *supra*, this PFD rejected the Attorney General's proposed disallowance for one of the four projects Mr. Coppola cites: namely, the Oakland Resiliency (CMS Line 2700) project. Conversely, this PFD does accept the Attorney General's proposed disallowance for the Taggart Compressor Replacement project, which project Mr. Coppola similarly asserts will not be placed in service until well past the end of the projected test year.<sup>1714</sup> Thus, the PFD recommends that the Commission adopt the Attorney General's proposed adjustment to the AFUDC in the amount of \$2,113,000.<sup>1715</sup>

Ms. Rogers states that the IT Shared Asset Charge is the cost that DTE Gas Company pays to DTE Electric Company for their use of the IT programs/software/equipment, owned by DTE Electric, that benefits both DTE Gas and DTE Electric Companies.<sup>1716</sup> She adds that DTE's total Shared Asset Charge for the test period is \$50.83 million.<sup>1717</sup> She states that DTE is projecting an IT shared asset charge of \$38.6 million, and that the total IT shared asset revenue approved by the Commission in Case No. U-21297 was \$41.7 million of which \$36.7 million is attributable to DTE Gas.<sup>1718</sup> She asserts that Staff recommends a \$1.9 million adjustment to the IT shared asset charge so that the cost DTE Gas is paying DTE Electric for the use of the jointly beneficial IT programs/software/equipment matches the revenue that DTE Electric has been approved to collect per the Commission's order in U-21297.<sup>1719</sup> She adds that DTE

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<sup>1714</sup> 4 Tr 1463-1464.

<sup>1715</sup> This revised adjustment amount is calculated from discovery response "AGDG-7.202a, b – AFUDC".

<sup>1716</sup> 4 Tr 1604. Citation omitted.

<sup>1717</sup> *Id.* Citation omitted.

<sup>1718</sup> 4 Tr 1605. Citation omitted.

<sup>1719</sup> 4 Tr 1606.

Gas admits the reason for the discrepancy and states the shared asset charge should be lowered by \$1.9 million.<sup>1720</sup> Mr. Hecht states that in conjunction with a decrease to the Shared Asset Deferral Mechanism Regulatory Asset of \$1,304,000, Staff is supporting a decrease of \$290,000 in the amortization expense of the Shared Asset Deferral Mechanism Regulatory Asset.<sup>1721</sup>

As DTE has agreed to the decrease to the Shared Asset Deferral Mechanism Regulatory Asset, this PFD recommends that the Commission adopt Staff's proposed disallowance based on the decrease of \$290,000 in the amortization expense of the Shared Asset Deferral Mechanism Regulatory Asset.

Ms. Rogers states that Staff recommends a 20% disallowance for IT projects with Level 2 cost estimates because of their incomplete, indefinite, and imprecise nature.<sup>1722</sup> She adds that Staff's recommendation of a 20% disallowance for IT projects with Level 2 cost estimates equates to a disallowance of \$0.63 million in the 9 months ending 9/30/2024 and \$1.13 million in the test year ending 9/30/2025 in capital, as well as \$0.12 million in O&M.<sup>1723</sup> As discussed previously, for the reasons stated, *supra*, this PFD recommends that the Commission adopt Staff's capital disallowance. As such, this PFD recommends that the Commission similarly adopt Staff's proposed O&M disallowance of \$120,780.

Ms. Rogers states that DTE's total Shared Asset Charge for the test period is \$50.83 million and that DTE is projecting an IT shared asset charge of \$38.6 million.<sup>1724</sup>

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<sup>1720</sup> Id. Citation omitted.

<sup>1721</sup> 4 Tr 1749

<sup>1722</sup> 4 Tr 1601.

<sup>1723</sup> 4 Tr 1601. Citation omitted.

<sup>1724</sup> 4 Tr 1604, 1605.

She adds that Staff recommends a \$1.9 million adjustment to the IT shared asset charge so that the cost DTE Gas is paying DTE Electric for the use of the jointly beneficial IT programs/software/equipment matches the revenue that DTE Electric has been approved to collect per the Commission's order in U-21297.<sup>1725</sup> She states that if DTE Gas paid the amount projected in the instant case, \$38.6 million, DTE Electric will gain an extra \$1.9 million that is unaccounted for, which represents an unnecessary burden to DTE Gas ratepayers.<sup>1726</sup> She adds that in response to discovery from the Attorney General, DTE Gas admits the reason for the discrepancy and states the shared asset charge should be lowered by \$1.9 million.<sup>1727</sup> Thus, this PFD recommends that the Commission adopt Staff's proposed disallowance of \$1.9 million.

Mr. Coppola states that DTE is forecasted Rents expense (capital use charges) of \$56.1 million, which amount represents an increase of \$4.8 million, or 9%, over the 2022 adjusted historical period.<sup>1728</sup> He adds that in response to discovery, DTE reported that the forecasted expense was based on forecasted costs in the DTE Electric rate case, which the Commission reduced in its rate order, and that DTE reported that the expense for Rents was overstated by \$2.5 million.<sup>1729</sup> Thus, he recommends that the Commission remove this amount from DTE's forecasted O&M expense. As such, this PFD recommends that the Commission adopt the Attorney General's proposed disallowance of \$2,500,000.

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<sup>1725</sup> 4 Tr 1606.

<sup>1726</sup> *Id.*

<sup>1727</sup> *Id.*

<sup>1728</sup> 4 Tr 1542; Ex. A-13, Sch. C5.6.

<sup>1729</sup> *Id.*; Ex. AG-48.

Mr. Coppola states that DTE provided information that shows that several executives of the Company, DTE Electric, and DTE Energy, along with certain members of DTE's Board of Directors, took 16 trips on the corporate leased aircraft in 2022 to investor and security analyst meetings and conferences, as well as to out of state Board of Directors meetings, with the portion of the cost billed to DTE in 2022 was \$68,910.<sup>1730</sup> He adds that DTE states that \$74,769 of expense was included in the projected test year in this rate case.<sup>1731</sup> He recommends that the Commission disallow recovery of costs for privately-hired corporate jet use, particularly since the travel pertains to investor and board of director matters that do not directly benefit customers but instead may benefit shareholders and remove the \$75,000 of costs that DTE reported it included in the projected test year.<sup>1732</sup>

This PFD agrees with the Attorney General. This PFD notes that DTE does not support the reasonableness of these expenses nor otherwise rebut the Attorney General's assertions, this PFD recommends that the Commission adopt the Attorney General's proposed \$74,769 disallowance.

Mr. Kehoe states that the projected test period O&M for TCARP Transmission Fees is \$10.72 million and that in the historical test year of 2022, \$0 million was spent resulting in a known and measurable change of \$10.72 million for the projected test period.<sup>1733</sup>

Mr. Kehoe states the projected test period O&M for TCARP Regulatory Asset Amortization is \$5.69 million, adding that in the historical test year of 2022, \$0 million was

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<sup>1730</sup> 4 Tr 1554.

<sup>1731</sup> 4 Tr 1554-1555; Ex. AG-53.

<sup>1732</sup> 4 Tr 1555.

<sup>1733</sup> 4 Tr 2021, Table 12.

spent resulting in a known and measurable change of \$5.69 million for the projected test period.<sup>1734</sup>

Mr. Kehoe states that the projected test period O&M for Washington Storage Contract Expiration is \$0 million and that in the historical test year of 2022, \$2.39 million was spent resulting in a known and measurable change of (\$2.39) million for the projected test period.<sup>1735</sup>

Mr. Kehoe states that the projected test period O&M for PSMS is \$1.18 million, adding that in the historical test year of 2022, \$0.73 million was spent resulting in a known and measurable change of \$0.45 million for the projected test period.<sup>1736</sup>

The projected test period O&M for Quality Assurance (QA) is \$1.00 million. In the historical test year of 2022, \$0.35 million was spent resulting in a known and measurable change of \$0.65 million for the projected test period.<sup>1737</sup>

The projected test period O&M for Records Management is \$0.43 million. In the historical test year of 2022, \$0.10 million was spent resulting in a known and measurable change of \$0.33 million for the projected test period.<sup>1738</sup>

The projected test period O&M for RSG Premiums is \$0.18 million. In the historical test year of 2022, \$0 million was spent resulting in a known and measurable change of \$0.18 million for the projected test period.<sup>1739</sup>

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<sup>1734</sup> 4 Tr 2022, Table 13.

<sup>1735</sup> 4 Tr 2023, Table 14.

<sup>1736</sup> 4 Tr 2023-2024, Table 15.

<sup>1737</sup> 4 Tr 2025-2026, Table 16.

<sup>1738</sup> 4 Tr 2027, Table 17.

<sup>1739</sup> 4 Tr 2028, Table 18.

### **Natural Gas Distribution**

Mr. Kehoe states that the projected test period O&M for natural gas distribution, excluding the cost of Company Use gas, is \$141.9 million out of the total \$246.8 million.<sup>1740</sup>

Mr. Kehoe states that the projected test period O&M for Mega Rule – Corrosion – Distribution Portion is \$0.11 million.<sup>1741</sup> He adds that there was no expense in the historical test year, resulting in a known and measurable change of \$0.11 million for the projected test period.<sup>1742</sup>

Mr. Kehoe states that the projected test period O&M for Legacy Cross Bore Inspections is \$0.10 million, and that in the historical test year of 2022, \$0.01 million was spent resulting in a known and measurable change of \$0.10 million for the projected test period.<sup>1743</sup>

Mr. Kehoe states that the projected test period O&M for the Gas Scheduling Optimizer O&M cost savings is (\$0.30) million.<sup>1744</sup> He adds that the projected test period O&M for Leak Detection and Repair (LDAR) is \$10.28 million.<sup>1745</sup>

### **Customer Service O&M Expenses**

Mr. Hatsios states that DTE Gas forecasts \$62.3 million in Customer Service O&M in the 8-month projected period ending September 30, 2025.<sup>1746</sup>

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<sup>1740</sup> Id.; Ex. A-13, Sch. C5.3.

<sup>1741</sup> 4 Tr 2035

<sup>1742</sup> Id., Table 19.

<sup>1743</sup> 4 Tr 2036, Table 20.

<sup>1744</sup> 4 Tr 2037, Table 21.

<sup>1745</sup> Id., Table 22.

<sup>1746</sup> 4 Tr 2437; Ex. A-13, Sch. C5.4.

Mr. Hatsios states that The Customer Service team supports delivery of highly satisfying customer experiences and drives improvement where needed.<sup>1747</sup> He adds that Customer Service is responsible for managing the customer support processes for both DTE Electric and DTE Gas.<sup>1748</sup>

### **Customer Accounts Expenses**

Mr. Hatsios states that the Customer Accounts Expenses category is primarily for work activities related to Supervision (\$1.9 million), Meter Reading (\$4.6 million), Customer Records and Collection (\$40.1 million), Customer 360 Amortization (\$1.4 million), Customer Collection-Merchant Fees (\$6.0 million), and Miscellaneous Customer Accounts Expenses (\$1.2 million).<sup>1749</sup>

### **Customer Service and Informational Expenses**

Mr. Hatsios states that the Customer Service and Informational Expenses category is primarily made up of activities related to Customer Assistance (\$2.8 million) and Miscellaneous Customer Service and Information Expenses of (\$2.8 million).<sup>1750</sup>

### **Marketing Expenses**

Mr. Decker states that DTE Gas Marketing projects \$57.0 million of O&M expense during the projected test period, which is equal to the actual 2022 annual expense of \$52.9 million, less \$1.1 million for the elimination of the Gas Voluntary Renewable Program, plus an adjustment for inflation.<sup>1751</sup>

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<sup>1747</sup> 4 Tr 2421.

<sup>1748</sup> 4 Tr 2422.

<sup>1749</sup> 4 Tr 2428.

<sup>1750</sup> 4 Tr 2434.

<sup>1751</sup> 2 Tr 116; Ex. A-13, Sch. C5.5.

### **Administrative and General Expenses**

Mr. Coppola states the information provided by DTE shows that several executives of DTE Gas, DTE Electric, and DTE Energy, along with certain members of DTE's Board of Directors, took 16 trips on the corporate leased aircraft in 2022 to investor and security analyst meetings and conferences, as well as to out of state Board of Directors meetings, and that the portion of the cost billed to DTE Gas in 2022 was \$68,910.<sup>1752</sup> He adds that DTE stated that \$74,769 of expense was included in the projected test year in this rate case.<sup>1753</sup> He recommends that the Commission disallow recovery of costs for privately-hired corporate jet use, particularly since the travel pertains to investor and board of director matters that do not directly benefit customers but instead may benefit shareholders, and thus recommend that the Commission remove the \$75,000 of costs that DTE reported it included in the projected test year.<sup>1754</sup>

### **New Hire VEBA And Employee Savings Plan Costs**

Mr. Cooper states that the New Hire Retiree VEBA expense is projected to increase from \$2.437 million in the historic test year to \$3.256 million in the projected test year, which reflects the growth in the number of plan participants due to new hires.<sup>1755</sup> He adds that the projected Employee Savings Plan was developed based on the 2022 expense, as adjusted for excess forfeitures in 2022, escalated by the most recent five-year average of the annual increase in DTE's Employee Savings Plan costs of 8.40%.<sup>1756</sup>

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<sup>1752</sup> 4 Tr 1554.

<sup>1753</sup> 4 Tr 1555; Ex. AG-53.

<sup>1754</sup> Id.

<sup>1755</sup> 4 Tr 2612; Ex. A-13, Sch. C5.9.

<sup>1756</sup> 4 Tr 2614.

He adds that this results in Employee Savings Plan expense for the projected test year of \$13.166 million compared \$10.368 million in the historical test year.<sup>1757</sup>

Noting that DTE used an 8.4% annual increase in the DTE's Employee Savings Plan costs based on recent DTE experience, increasing the historic year 2022 expense amount used in its average, Mr. Rueckert states that Staff does not agree with increasing the historical amount of 2022, noting that the difference in forfeitures for 2022 is 1.6% compared to the total expense for 2022 of \$16,274,000.<sup>1758</sup> He states that Staff updated DTE's expense in 2023, using a 5-year average annual growth rate (AAGR) from years 2019-2023 based on DTE's total ESP expense with 2022 unadjusted.<sup>1759</sup> He adds that the annual change in ESP expense from years 2019-2023 produce a 7.15% AAGR, which rate was applied to historic year 2023 expense resulting in a projection of \$11,483,000, a reduction of \$1,683,000 from DTE's projection of \$13,166,000.<sup>1760</sup>

### **Rents – Capital Use Charges**

Noting that DTE shows forecasted Rents expense (capital use charges) of \$56.1 million, which amount represents an increase of \$4.8 million, or 9%, over the 2022 adjusted historical period, DTE reports that the expense for Rents was overstated by \$2.5 million, and thus, he recommends that the Commission remove this amount from DTE's forecasted O&M expense in this rate case.<sup>1761</sup>

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<sup>1757</sup> Id.

<sup>1758</sup> 4 Tr 1652.

<sup>1759</sup> Id.

<sup>1760</sup> Id.; Ex. S-9.2, Ex. S-9.0.

<sup>1761</sup> 4 Tr 1542; Ex. AG-48.

### **Other Employee Benefits**

Mr. Cooper states DTE's Other Employee Benefits – which include Accrued Vacation, Executive and Supplemental Retirement Plans, Supplemental Severance Plan costs, Wellness Program, Life Insurance, Long-Term Disability, costs associated with the Affordable Care Act (ACA) Supplemental Savings Plan (SSP), Deferred Compensation, General Benefits, Benefit Plan Administration Fees and Retirement Administration Fees -- are projected to increase from \$5.036 million in the historic test year to \$7.270 million in the projected test year.<sup>1762</sup>

Mr. Cooper states that the total projected employee pensions and benefits costs are \$45.732 million, which is adjusted for the impact of the portion of these costs to be transferred and capitalized and the elimination of costs allocated to DTE's separate surcharge program and results in an employee pensions and benefits expense of \$43.125 million for the projected test year.<sup>1763</sup>

### **Labor Cost Escalation**

Mr. Cooper states based on existing Collective Bargaining Agreements, DTE is obligated to increase pay rates by at least 3% annually through the term of the contracts, and that all non-management employees received an overall pay increase of 3% in 2023 based on based on a review of pay practices of other employers, changes in the external competitive market and internal pay equity.<sup>1764</sup> As such, he states that he has determined that annual escalations of 3.0% for 2023, 2024, and 2025 are a conservative estimate of DTE's expected increase in its labor rates.<sup>1765</sup>

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<sup>1762</sup> 4 Tr 2629-2630; Ex. A-13, Sch. C5.9.

<sup>1763</sup> 4 Tr 2634; Ex. A-13, Sch. C5.9.

<sup>1764</sup> 4 Tr 2634-2635.

<sup>1765</sup> 4 Tr 2635.

## **Manufactured Gas Plant Remediation Expenses**

Mr. Brennan states there are several State and Federal statutory requirements that provide for handling of the MGP remediation.<sup>1766</sup> He adds that DTE Gas currently has the responsibility for former MGP sites located in Detroit (four sites), Ann Arbor (two sites), Belding (one site), Grand Rapids (one site), Greenville (one site), Ludington (one site), Melvindale (one site), Mt. Pleasant (one site), Muskegon (one site), and Muskegon Heights (one site), as well as for nine former holder sites located in Detroit (seven sites), Chelsea (one site) and Wyandotte (one site).<sup>1767</sup> He states that DTE Gas has completed the initial Site Investigation for all 14 former MGP sites and the nine former holder sites, and that, based on that work, DTE Gas concluded that the 14 former MGP sites and two of the holder sites (Coolidge and Lynch) required additional investigation under Part 201.<sup>1768</sup> He adds that the Remedial Investigation, Initial Response Action, Feasibility Study and Remedial Action phases are all in progress or have been completed for the 14 former MGP sites.<sup>1769</sup>

Mr. Brennan states that DTE Gas has incurred remediation costs of approximately \$112.5 million to date, including costs reflected in this case of approximately \$6.4 million.<sup>1770</sup>

Mr. La Pan states Staff has determined that DTE's environmental response activities at its former MGP sites from November 1, 2020 through August 31, 2023, as well as the actual costs associated with those activities, are reasonable and prudent.<sup>1771</sup>

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<sup>1766</sup> 4 Tr 2404.

<sup>1767</sup> 4 Tr 2408-2409.

<sup>1768</sup> 4 Tr 2409.

<sup>1769</sup> Id.; Ex. A-13, Sch. C13.2.

<sup>1770</sup> 4 Tr 2412, 17; Ex. A-13, Sch. C13.3, Sch. C13.4.

<sup>1771</sup> 4 Tr 1710.

He adds that Staff found that DTE has shown reasonable and prudent effort to reduce costs and/or alleviate its financial liabilities at their historic MGP sites.<sup>1772</sup> Thus, Staff recommends the Commission approve \$6,355,736 as reasonably and prudently incurred costs for environmental response activities at the Company's former MGP sites from November 2020 to August 2023, which is inclusive of the 2019 costs of \$866,445.<sup>1773</sup>

### **Depreciation and Amortization**

Mr. Hecht states that Staff supports a decrease to DTE's projected depreciation expense of \$13,827,000 to \$229,392,000, which is composed of a \$442,000 decrease comprised of the corresponding impacts on depreciation and amortization expense resulting from Staff adjustments to DTE's historic and projected capital expenditures, and a \$13,385,000 decrease as a result of using the depreciation rates approved in Case No. U-20118.<sup>1774</sup> He adds that DTE filed its rate case with rates that are currently not approved, but being sought for approval, in its Depreciation Case No. U-21384, and that Staff's adjustment moves the depreciation expense in the instant case to an amount using the current approved depreciation rates from Case No. U-20118 at the time DTE made its rate case filing.<sup>1775</sup> He states that Staff recommends that if an order is issued for Depreciation Case No. U-21384 prior to an order in the instant case, the Commission should implement the new ordered depreciation rates in the instant rate case, but that until Depreciation Case No. U-21384 is resolved, the currently approved rates from Case No. U-20118 should be used.<sup>1776</sup>

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<sup>1772</sup> 4 Tr 1711.

<sup>1773</sup> Id.

<sup>1774</sup> 4 Tr 1750.

<sup>1775</sup> 4 Tr 1751.

<sup>1776</sup> 4 Tr 1752.

Mr. Coppola states that as a result of the reductions in capital expenditures proposed in his testimony and the impact on capital additions included in rate base, he calculated a reduction in depreciation expense of \$3,409,000, and thus recommends that the Commission reduce the depreciation expense proposed by DTE for the projected test year by \$3,409,000.<sup>1777</sup> Mr. Coppola used DTE's proposed depreciation rates DTE supported in Case No. U-21384.<sup>1778</sup>

This PFD agrees with Staff that the currently approved depreciation rates from Case No. U-20118 should be used until an order is issued in Case No. U-21384. The differences in depreciation expenses arise from the differences in capital expense amounts recommended by the parties. The depreciation expense should be recalculated based on the determinations in the final order.

### **Property and Other Taxes**

Mr. Hecht states that Staff is proposing to decrease DTE's property tax expense test year projection by \$58,000, which reduction is the corresponding impact on property tax expense resulting from the test year plant impacts of Staff's adjustments to DTE's historic and projected capital expenditures.<sup>1779</sup>

Mr. Coppola states that based on the adjustments to be made to DTE's proposed capital expenditures, which reductions lower the amount of property tax expense that the DTE will incur during the projected test year, he has calculated the reduction in property tax expense of \$5,019,000 million, and thus recommends that the Commission reduce DTE's property tax expense by this amount for the projected test year.<sup>1780</sup>

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<sup>1777</sup> 4 Tr 1566.

<sup>1778</sup> Ex. AG-20, n. 2; Ex. A-13, Sch. C6, p. 1, n. 1.

<sup>1779</sup> Id.; Ex. S-3, sch. C-1.

<sup>1780</sup> 4 Tr 1566; Ex. AG-20.

## **Cost of Service**

Mr. Krysinski states that a cost of service study (COSS) is an allocation of a company's total costs of doing business (i.e., total revenue requirement) to all customer classes at a rate schedule level.<sup>1781</sup> He adds that a COSS determines the cost of providing service to each customer class and is used as the basis to develop the rates and charges needed for DTE to earn its required rate of return.<sup>1782</sup>

Mr. Krysinski states that the COSS allocation schedules are determined on Exhibit A-16, Schedule F1.2 for the Proposed COSS.<sup>1783</sup> He adds that certain costs are not allocated to all rate classes as there are plant items and expenses that relate to more than one of the above functions and allocations for these items are made based on the appropriate combination of the allocation results for other costs and plant items.<sup>1784</sup> He states that additional allocation schedules are developed to allocate costs that are not allocated by one of the base component allocation schedules, whereby the process involves determining the class cost for subsets of all costs allocated by the base schedules, totaling those subsets of costs for each rate class grouping, and then dividing each class total by the sum for all classes.<sup>1785</sup> He adds that the allocation methods used in the Proposed COSS are the same as those approved by the Commission in their Order on December 9, 2021 in Case No. U-20940, which includes the allocation of Uncollectibles based on the overall cost of service including cost of gas (Allocation Schedule #20).<sup>1786</sup>

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<sup>1781</sup> 4 Tr 2147.

<sup>1782</sup> Id.

<sup>1783</sup> 4 Tr 2148.

<sup>1784</sup> 4 Tr 2149.

<sup>1785</sup> Id.

<sup>1786</sup> 4 Tr 2151; Ex. A-16, Sch. F1.1.

Mr. Krysinski states the Commission has reaffirmed its long-standing approval of two demand / capacity allocation methods as approved in DTE's last five gas rate cases, including Case No. U-20940, with the Average and Peak (A&P) allocation method being approved for allocating functionalized transportation costs and non-customer related distribution costs, and for storage costs, a blended method of 50% cost allocation on the Peak method and 50% cost allocation on the percentage of storage capacity.<sup>1787</sup>

Mr. Krysinski states that the A&P allocation method blends a rate class's average demand and peak demand giving a weighted percent for use in allocating transmission and distribution costs.<sup>1788</sup> He adds that the A&P method uses an average consumption schedule as an integral part in allocating demand costs.<sup>1789</sup> He states that under the A&P method, the portion used to meet the maximum system load is determined by dividing each rate class's peak day consumption by total peak day consumption.<sup>1790</sup>

Mr. Krysinski states that the storage demand allocation method was reaffirmed by the Commission in Case Nos. U-18999, U-20642, and U-20940.<sup>1791</sup> He adds that this method combines a 50% blend of storage capacity and 50% peak demand to yield the Storage Peak Allocator.<sup>1792</sup> He states that for the projected test year Proposed COSS, he used DTE's January design peak day requirement of 2.5 Bcf from DTE Gas's GCR Plan, Case No. U-21271.<sup>1793</sup>

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<sup>1787</sup> Id.

<sup>1788</sup> 4 Tr 2151.

<sup>1789</sup> Id.

<sup>1790</sup> 4 Tr 2151-2152.

<sup>1791</sup> 4 Tr 2152.

<sup>1792</sup> Id.

<sup>1793</sup> 4 Tr 2153.

Mr. Krynski states that that no changes to the rate schedules have been made to the rate schedules in the Proposed COSS since DTE's last rate case, Case No. U-20940.<sup>1794</sup> He adds that merchant fees are directly assigned to rate classes consistent with the methodology utilized by DTE in its last gas rate case, U-20940, whereby these fees are assigned only to those rate classes which are permitted to use this method of payment and in proportion to the total credit card payments for each of these classes during the historical test period.<sup>1795</sup>

Mr. Krynski states the starting point for rate design is the net cost of service by rate grouping, with residential customers taking service under Rate A and 2A being treated as one group for determining the distribution charge, and with monthly customer charges for Rates 2A Meter Class II and GS-1 are set to be equal and Rates GS-1 and GS-2 are also grouped together.<sup>1796</sup> He adds that service charge revenue is subtracted from the rate making cost of service to yield the amount to be collected in the distribution charge, with the amount to be collected in the distribution charge being divided by the appropriate volume to obtain the unit rate.<sup>1797</sup>

Mr. Krynski states that the Commission required DTE to provide a second COSS consistent with Staff's second alternate COSS.<sup>1798</sup> He adds that DTE Gas in its last rate case, Case No. U-20940, submitted two alternate cost-of-service studies which incorporated the results of supplemental studies prepared by DTE.<sup>1799</sup> He states that at a high-level, the second alternate COSS provided in Case No. U-20940 split distribution

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<sup>1794</sup> 4 Tr 2154.

<sup>1795</sup> Id.; Ex. A-16, Sch. F1.1.

<sup>1796</sup> 4 Tr 2160.

<sup>1797</sup> Id.

<sup>1798</sup> 4 Tr 2162.

<sup>1799</sup> Id.

main plant and IRM Main Replacement Program costs into high- and low-pressure.<sup>1800</sup> He adds that Staff subsequently updated costs in the DTE provided second alternate COSS to reflect costs approved in the order, which version came to be known as “Staff’s second alternate COSS.”<sup>1801</sup>

Mr. Krynski states that DTE has prepared an Alternate COSS which uses the same methodology as the second alternate cost of service study provided by DTE in its last gas rate case, updated for costs in the instant case, as well as updated supplemental studies.<sup>1802</sup> He states that the Alternate COSS utilizes the same costs as DTE Gas’s Proposed COSS and has been modified by splitting distribution main plant and IRM Main Replacement Program into high-pressure and low-pressure costs.<sup>1803</sup> He adds that high-pressure distribution main costs are allocated to customers taking service from DTE’s high-pressure and low-pressure distribution system, while excluding volumes taken from the transmission system, and that low-pressure distribution main costs are allocated to customers taking service from the low-pressure distribution system only.<sup>1804</sup>

Mr. Krause states that Staff’s COSS functionalizes, classifies, and allocates DTE Gas Company’s costs as projected by Staff to customer classes based on a set of schedules developed for such a purpose.<sup>1805</sup> He adds that Staff’s COSS begins with a review of DTE’s filed COSS, with input data being traced to original exhibits, calculations for the functionalization, classification, and allocation were confirmed, and allocation

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<sup>1800</sup> Id.

<sup>1801</sup> Id.

<sup>1802</sup> Id.; Ex. A-24, Sch. N1 – Revised.

<sup>1803</sup> 4 Tr 2163.

<sup>1804</sup> Id.

<sup>1805</sup> 4 Tr 1720.

schedule workpapers were verified in the same manner as the COSS.<sup>1806</sup> He states that the COSS was then updated with adjustments provided by other Staff to capital expenditures, operations and maintenance (O&M) and other expenses, rate of return, cost of gas, and present revenue.<sup>1807</sup> He adds that cost allocation and the calculation of customer charges were performed as supported by Staff's positions in the case.<sup>1808</sup>

Mr. Krause states that Staff performed two cost-of-service-studies: one to match DTE's proposed COSS and one to match the high and low pressure COSS that was filed by DTE.<sup>1809</sup> He adds that the high/low alternative COSS was used by Staff to inform rate design.<sup>1810</sup>

Mr. Krause states that Staff modified DTE's calculation of customer charges, which it based on the method approved in DTE's previous gas rate case, albeit using a combination of historical and projected expenses.<sup>1811</sup> He adds that Staff proposes to only rely on historic amounts for customer charges in the instant case.<sup>1812</sup> He asserts that test-year capital as presented by DTE is split into separate accounts or categories based on the historic composition of those accounts in relation to total historic capital.<sup>1813</sup> He argues that this treatment may be acceptable if the costs compositions did not change year to year but notes that the costs compositions change year to year.<sup>1814</sup> Thus, he concludes that DTE's calculation fails to reflect projections of costs appropriate for inclusion in the

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<sup>1806</sup> Id.

<sup>1807</sup> Id.

<sup>1808</sup> Id.

<sup>1809</sup> Id.

<sup>1810</sup> Id; Ex. S-15, S-6.

<sup>1811</sup> 4 Tr 1720-1721.

<sup>1812</sup> 4 Tr 1721.

<sup>1813</sup> Id.

<sup>1814</sup> Id.

customer charge.<sup>1815</sup> He adds that utilizing only historical costs ensures that DTE's method of spreading projected costs does not include costs that are inappropriate for inclusion in the customer charge.<sup>1816</sup> He states that the calculation results in a residential customer charge of \$14.50, and thus Staff recommends the following customer charges: Residential - \$14.50, School - \$270.00, and GS-1 \$50.00, with all other customer charges being determined by rate design.<sup>1817</sup>

Mr. Coppola disagrees with DTE's proposal to increase the monthly service charge for residential customers (Rate Schedules A and 2A) from \$13.50 to \$17.60 per month, and its proposal to increase the monthly customer service charge for small commercial customers in rate schedule GS-1 from \$40.00 to \$50.00.<sup>1818</sup> He states that the proposed change from \$13.50 to \$17.60 per month represents an increase of 30% and that such a large increase could cause rate shock to customers in smaller households who use less gas than the average customer.<sup>1819</sup> He adds that fixed monthly charges also discourage energy conservation, such that it is best to increase the volumetric rate paid by customers because the higher cost encourages conservation.<sup>1820</sup> He states that small commercial customers who take service under rate GS-1 would see an increase of 25% in their monthly charge, which is a significant increase for smaller commercial customers.<sup>1821</sup>

Mr. Coppola recommends that the Commission maintain the current residential monthly customer charge of \$13.50, noting that the monthly service charge was increased

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<sup>1815</sup> Id.

<sup>1816</sup> Id.

<sup>1817</sup> Id.

<sup>1818</sup> 4 Tr 1568.

<sup>1819</sup> Id.

<sup>1820</sup> Id.

<sup>1821</sup> Id.

\$1.25 in 2022 in DTE's last rate case.<sup>1822</sup> He adds that DTE's proposed monthly charge of \$17.60 would result in an annual charge of \$211, which would represent a large portion of the total annual gas bill for small households.<sup>1823</sup> He states that if the Commission sees some merit in increasing the monthly service charge, in the interest of rate gradualism, he recommends that the Commission not increase the monthly charge by more than \$1 to \$14.50.<sup>1824</sup> He adds that for the GS-1 rate, the Commission should maintain the current monthly charge of \$40.00, which was increased by \$8.00 in 2022, as the last increase of 20% was rather large and another increase should be avoided at this time.<sup>1825</sup>

Regarding Mr. Coppola's proposals, Mr. Krynski states that his proposed level of customer charges for these rate classes is not supported by cost-based calculations and does not align with accepted regulatory practice.<sup>1826</sup> He notes that methodology long-adopted by the Commission regarding customer charges.

The maximum allowable service charge would be limited to those costs associated directly with supplying service to a customer. Only costs associated with metering, the service lateral, and customer billing are includable since these are costs that are directly incurred as a result of a customer's connection to the gas system.<sup>1827</sup>

He adds that the guidance in Case Nos. U-4771 and U-4331 was reconfirmed by the Commission in its final order in Case No. U-17999 and utilized to guide the Commission approved residential customer charges in DTE Gas Rate Case Nos. U-

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<sup>1822</sup> 4 Tr 1569.

<sup>1823</sup> *Id.*

<sup>1824</sup> *Id.*

<sup>1825</sup> *Id.*

<sup>1826</sup> 4 Tr 2175.

<sup>1827</sup> 4 Tr 2175, quoting Case No. U-4331, Order, p. 30, January 18, 1974; 3 Tr 1251.

18999, U-20642 and U-20940.<sup>1828</sup> He asserts that the proposed methodology employed by DTE Gas consistent with accepted regulatory practice.<sup>1829</sup>

Also in rebuttal, Mr. Krynski states that DTE's current method for splitting distribution plant using historical ratios is a common practice in cost-of-service and is a reasonable approach which reflects investments made in DTE's distribution system.<sup>1830</sup> He adds that not all costs embedded in the residential customer charge rely on historical ratios; customer service costs reflect test-year cost projections made at the account level.<sup>1831</sup> He asserts that no evidence has been provided demonstrating that the current approach results in inaccurate costs or that customers have been harmed.<sup>1832</sup> Finally, he argues that using historical costs for one subpart of rate design while otherwise using forecasted costs and determinants is broadly inconsistent.<sup>1833</sup> He recommends the Commission reject Staff's proposal of using historical costs to calculate the residential customer charge, and instead, recommends the Commission approve DTE's current approach, which has guided Commission-approved residential customer charges going back to at least Case No. U-17999 (2016) and updating the residential customer charge based on projected costs approved in the final order of the instant case.<sup>1834</sup>

Noting Mr. Revere's recommendation that the Commission require DTE to continue filing the alternate COS in future cases, Mr. Krynski reiterates that preparation of the Alternate COSS is manually-intensive and time consuming.<sup>1835</sup> He states that while

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<sup>1828</sup> Id.

<sup>1829</sup> 4 Tr 2176.

<sup>1830</sup> 4 Tr 2173.

<sup>1831</sup> Id.

<sup>1832</sup> Id.

<sup>1833</sup> Id.

<sup>1834</sup> 4 Tr 2173.

<sup>1835</sup> 4 Tr 2174.

DTE would prefer not to continue performing the Alternate COSS in future rate cases, if the Commission requires it in their Order in the instant case, DTE proposes an alternative whereby the Commission allows DTE to reuse workpapers TJK-15 (Distribution Mains – High vs. Low<sup>7</sup> Pressure Cost Study) and TJK-16 (Volumes Split by Delivery Type) provided in this instant case to prepare the Alternate COSS in DTE’s next rate case.<sup>1836</sup> He adds that the projected test year costs utilized in the next rate case filing made by DTE would be used to update both the Alternate COSS and DTE’s primary, Proposed COSS.<sup>1837</sup> He states that DTE further proposes that updates to these two workpapers would be made on a structured, five-year cadence to ensure that changes over time are properly captured and incorporated into future Alternate COSS’s as may be required.<sup>1838</sup>

MPLP states that DTE’s cost of service study – which uses a weighted peak demand and throughput allocation method (“A&P”) method to allocate fixed demand-related delivery system costs -- is at odds with system design and cost causation.<sup>1839</sup> Mr. Collins states that if the system was designed to meet average throughput, it would be impossible for DTE to deliver enough gas to meet customer demands on the coldest days in the winter.<sup>1840</sup>

Mr. Collins recommends that a peak day demand allocation method be used in place of DTE’s proposed demand and throughput.<sup>1841</sup> He states that Design day peak demand by class best reflects the actual design of the system and is basically the same as the straight fixed variable method (“SFV”) endorsed by the Federal Energy Regulatory

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<sup>1836</sup> Id.

<sup>1837</sup> Id.

<sup>1838</sup> Id.

<sup>1839</sup> 4 Tr 791.

<sup>1840</sup> Id.

<sup>1841</sup> Id.

Commission.<sup>1842</sup> He adds that use of this method would make DTE's large transportation rates much more competitive.<sup>1843</sup>

Mr. Collins asserts that as a reasonable alternative solution, the "75/25" method is a far superior, stable and more equitable form of cost allocation than DTE's current A&P method.<sup>1844</sup> He notes that the Commission has adopted this method for electric utilities in Michigan for many years.<sup>1845</sup> He states that the 75/25 method allocates 75% of fixed costs on a demand basis and 25% of fixed costs on an average energy basis.<sup>1846</sup> He asserts that increases in system load factor do not increase the average throughput weighting, thereby removing the bias against the system efficiency increase.<sup>1847</sup>

Mr. Collins states that correcting DTE's cost of service to a peak day method shows that Rate XXLT should be significantly decreased.<sup>1848</sup> He adds that limiting the throughput allocation to no more than 25% consistent with the electric cost allocation shows that Rate XXLT should be modestly decreased.<sup>1849</sup>

Mr. Collins states that the Rate XXLT rate class is not adequately homogeneous with respect to the cost of service characteristics.<sup>1850</sup> He asserts that to the extent low-pressure distribution customer(s) are allowed on the rate, those customer(s) should pay an additional charge to recover the cost associated with the low pressure distribution

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<sup>1842</sup> Id.

<sup>1843</sup> Id.

<sup>1844</sup> Id.

<sup>1845</sup> Id.

<sup>1846</sup> Id.

<sup>1847</sup> Id.

<sup>1848</sup> Id.

<sup>1849</sup> Id.

<sup>1850</sup> Id.

required for service.<sup>1851</sup> He adds that customers served at transmission should not pay for distribution service.<sup>1852</sup>

Mr. Collins states that he used DTE's model to perform a peak day demand cost of service study and also corrected the allocation of distribution-other to the Rate XXLT class.<sup>1853</sup> He adds that the results of this study indicate that transportation customers are providing revenues significantly in excess of their cost of service.<sup>1854</sup>

Mr. Collins argues that the alternative cost of service study shown in DTE Exhibit A-24 is problematic and should not be used for revenue distribution in this proceeding.<sup>1855</sup> He asserts that the alternative study is a significant departure from past practice, produces harsh impacts to certain classes and to customers served by transmission service such as Michigan Power, is not reflective of current rate structures and would take significant time and resources to investigate and correct.<sup>1856</sup>

In rebuttal, Mr. Krynski states that the Commission has consistently approved the use of the A&P method since December 1988 in DTE Gas's general rate case U-8812.<sup>1857</sup> Regarding ABATE's proposal to implement a distribution surcharge specific to Rate XXLT customers that take service from the distribution system, he replies that EUT classes were originally designed on the basis of volumes, not delivery type, and argues that implementing a distribution surcharge at this time would be inherently unfair to customers who previously connected without regard to delivery type.<sup>1858</sup> Regarding Mr. Collins

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<sup>1851</sup> Id.

<sup>1852</sup> Id.

<sup>1853</sup> 4 Tr 801; Ex. MPL-2.

<sup>1854</sup> 4 Tr 802.

<sup>1855</sup> Id.

<sup>1856</sup> 4 Tr 792.

<sup>1857</sup> 4 Tr 2178.

<sup>1858</sup> 4 Tr 2179.

calculation of a proposed distribution surcharge of \$0.0654 per Mcf based on Rate XXLTLow-pressure distribution usage of 3,806,336 Mcf., he states that these costs were incurred to serve all distribution volumes, both low- and high- pressure, and thus, it would be inappropriate to base the surcharge on low pressure volumes used by Rate XXLTL only.<sup>1859</sup>

Also, in rebuttal, regarding Mr. Collins' s claims that distribution-other costs should only be allocated to XXLTL based on the total class usage, as it was conceived as a transportation/high-pressure rate and only a small portion of volumes on the rate are at low-pressure, and his claims that the allocation to XXLTL should be "corrected" to only be based on the low-pressure volumes, Mr. Revere counters that Staff might agree if it were shown that these costs were only related to the low-pressure service provided to XXLTL, but asserts that Mr. Collins did not show this.<sup>1860</sup> He adds that Mr. Collins ignored the fact that a substantial portion (in fact, a majority) of the volumes on XXLTL are also taking service from the high-pressure distribution system.<sup>1861</sup> He asserts that the proposed allocation method effectively assumes that the costs in these Other Distribution plant accounts are limited to low-pressure distribution but that no evidence was presented that would support this assumption.<sup>1862</sup> Regarding Mr. Collins statement that he claims no knowledge that there has been a "showing that system load factor under the A&P methodology is the appropriate weighting mechanism, Mr. Revere replies that using the

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<sup>1859</sup> Id.

<sup>1860</sup> 4 Tr 1666.

<sup>1861</sup> Id.

<sup>1862</sup> 4 Tr 1667.

load factor to do the weighting is definitionally how this recognized method is conducted.<sup>1863</sup>

Mr. Revere states that Staff disagrees with Mr. Collins' assertion that the XXLT increase be limited to the results of the 75/25 study, asserting that limiting the increase to XXLT based on an inappropriate method is unjustifiable and should be rejected.<sup>1864</sup>

Regarding Mr. Collins proposal for an additional charge for low-pressure volumes on rate XXLT reflecting costs associated with the low-pressure distribution system, Mr. Revere states that ignores the cost difference between all pressures (transmission, high-pressure, and low-pressure) and chooses to focus on one, adding that there are a number of costs for which it is difficult to determine what portion is associated with which pressure level, so calculating such charges accurately and appropriately would be difficult if not impossible.<sup>1865</sup> He adds that the proposal ignores the realities of a breakeven-based class definition, as the delineations between the breakevens associated with each transportation schedule within the transportation class are effectively arbitrary; that is, the schedules are defined as they are due to the breakeven points, not due to any consideration of differential use of the system as they are for, say, electric distribution rates.<sup>1866</sup>

ABATE asserts that DTE's proposed CCOS relies on the Peak and Average ("P&A") method for the allocation of transmission and distribution capacity costs, and because the P&A method does not reflect cost-causation, it should be rejected.<sup>1867</sup> Ms.

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<sup>1863</sup> Id.

<sup>1864</sup> 4 Tr 1668.

<sup>1865</sup> Id.

<sup>1866</sup> 4 Tr 1668.

<sup>1867</sup> 4 Tr 1261.

York states that DTE's proposed revenue apportionment results in about a 1.6x system average increase for Rate XXL and a 1.35x system average increase for Rate XL.

Ms. York states that DTE has provided evidence showing that Design Day Demand is the load characteristic that drives investment in transmission and distribution capacity costs, and thus, a Design Day Demand allocation of these costs would produce the most accurate measure of DTE's cost of providing service to each customer class.<sup>1868</sup> She adds that the Design Day Demand CCOS shows that a rate decrease would be required for Rate XXL to reach cost of service, and that a below-system average increase (0.87x) would be required for Rate XL to reach cost of service.<sup>1869</sup>

Ms. York states that to the extent that the Commission prefers to continue relying on a partial energy-weighted method of allocating capacity costs, she recommends that the Average and Excess Demand ("AED") approach be used, instead of the P&A method.<sup>1870</sup> She argues that relative to the P&A method, the AED method more accurately assigns the transmission and distribution capacity costs to the lower-load factor, weather sensitive customer classes that drive the need for capacity in excess of the amount needed to provide firm service to the system and each customer class on non-peak days.<sup>1871</sup> She recommends an alternative revenue apportionment reflecting no rate change for Rate XXL, and recommends bringing Rate XL to cost of service based on a Design Day Demand CCOS with a 0.87x system average increase.<sup>1872</sup> She adds that her proposed revenue allocation mitigates the increase that would be required for the

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<sup>1868</sup> Id.

<sup>1869</sup> Id.

<sup>1870</sup> Id.

<sup>1871</sup> Id.

<sup>1872</sup> Id.

Residential class (“Rate A”) to reach cost of service based on the results of a Design Day Demand CCOS.<sup>1873</sup> Alternatively, she recommends a system average increase across all classes, provided DTE commits to provide a properly conducted AED CCOS in its next rate case.<sup>1874</sup> She adds that her alternative revenue apportionment would reflect a compromise between the P&A and Design Day Demand CCOS until an AED CCOS is conducted.<sup>1875</sup>

Ms. York states that DTE’s Preferred Class Cost of Service study (CCOS) would result in increases well above the system average for Rate XLT, Rate XXL, and Exelon, but that DTE’s proposed revenue apportionment, while generally based on the results of its Preferred CCOS, reflects adjustments in consideration of gradualism.<sup>1876</sup> She asserts that DTE’s proposed spread of the revenue deficiency is not reasonable, as DTE’s proposed revenue apportionment is based on the results of an inaccurate CCOS.<sup>1877</sup> She states that DTE’s CCOS does not allocate transmission and distribution main capacity costs in accordance with the load characteristic that drives DTE’s investment in transmission and distribution main capacity.<sup>1878</sup> She adds that an accurate CCOS based on the Design Day Demand method of capacity cost allocation shows that a rate decrease is warranted for certain transportation classes to reach cost of service.<sup>1879</sup> She states that she would not oppose an equal percent increase across all customer classes for purposes

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<sup>1873</sup> Id.

<sup>1874</sup> Id.

<sup>1875</sup> Id.

<sup>1876</sup> 4 Tr 1271, Table JAY 3.

<sup>1877</sup> 4 Tr 1272.

<sup>1878</sup> 4 Tr 1272

<sup>1879</sup> Id.

of this case, so long as DTE commits to provide a CCOS using the AED allocation method as an alternative to the P&A CCOS in its next rate case.<sup>1880</sup>

Ms. York states that she disagrees with the use of the P&A allocator to allocate the cost of transmission and distribution main capacity across rate classes in both the Preferred and Alternate CCOS models, as the P&A allocator does not allocate the cost of capacity in line with cost-causation, and distorts the accuracy of DTE's CCOS models.<sup>1881</sup> Noting that the Commission has accepted the use of the P&A allocator for transmission and distribution main capacity cost in past rate cases, she states that she is requesting that the Commission reconsider the merits of using the P&A allocation factor.<sup>1882</sup> She adds that other jurisdictions have adopted cost allocation methods that more accurately measure each class's cost of service than the P&A method.<sup>1883</sup>

Ms. York states that the transmission and distribution main capacity costs allocated to each class using the P&A allocation method do not align with how customers cause the capacity needed by DTE to provide firm service to the lower-load factor customer classes every day of the year, including the peak day.<sup>1884</sup> She adds that the Commission's prior adoption of this method simply reflects the fact that the P&A allocator assigns less transmission and distribution main capacity cost to the lower-load factor classes than a purely demand-based approach; that is, the "compromise" that the P&A allocation method strikes between high- and low-load factor customer classes does not reflect cost of service.<sup>1885</sup>

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<sup>1880</sup> 4 Tr 1273.

<sup>1881</sup> *Id.*

<sup>1882</sup> 4 Tr 1274-1276.

<sup>1883</sup> 4 Tr 1276.

<sup>1884</sup> 4 Tr 1282.

<sup>1885</sup> *Id.*

Ms. York states that DTE does not incur different unit costs of capacity for different customer classes; rather, the utility incurs capacity cost to meet the total Design Day Demand of all customers on its system.<sup>1886</sup> She adds that in order to accurately reflect cost-causation, every class should be assigned the same system average unit cost of capacity, and that, instead, the P&A method allocates an above-system average unit cost of capacity to higher-load factor classes, and allocates a below-system average unit cost of capacity to lower-load factor classes.<sup>1887</sup>

Ms. York states that to the extent that the Commission does not support a purely demand-based allocation of capacity costs, the AED method is more reasonable and more accurate than the P&A method.<sup>1888</sup>

Ms. York states that while Staff's adjusted version of DTE's Preferred CCROSS shows that an increase of about \$3.7 million, or 11.7%, would be needed for the XXLT class to reach cost of service, Staff proposes an increase of \$9.2 million, or 29.3%, or 7x the system average, based on the results of the Alternate CCROSS.<sup>1889</sup> She adds that despite Staff's proposed revenue deficiency being about 34% less than DTE's, Staff's revenue spread assigns approximately \$5.5 million more (\$9.164 million – \$3.671 million) to the XXLT class than indicated by DTE's Preferred CCROSS model, and about \$4.5 million more (\$9.164 million - \$4.613 million) than proposed by DTE in its recommended revenue apportionment.<sup>1890</sup>

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<sup>1886</sup> 4 Tr 1286.

<sup>1887</sup> *Id.*

<sup>1888</sup> 4 Tr 1290.

<sup>1889</sup> 4 Tr 1302.

<sup>1890</sup> *Id.*

In rebuttal, Mr. Krynski states that he disagrees with ABATE's proposal regarding Design Day Demand, noting that the Commission has consistently approved the use of the A&P method since December 1988 in DTE Gas's general rate case U-8812.<sup>1891</sup> Regarding ABATE's proposal where XXL rates remain unchanged, and a downward adjustment is applied to Rate XLT based on the use of Design Day Demand, he recommends this proposal be rejected as the proposed revenue apportionment keeping XXL rates unchanged is arbitrary and does not align with the class cost of service revenue requirement.<sup>1892</sup> Regarding ABATE's proposal to apply a system average increase across all classes, he replies that it is arbitrary and does not align with cost of service.<sup>1893</sup> Regarding ABATE's recommendation that DTE be required to provide an Average & Excess Demand COSS in its next rate case, he argues that DTE should not be required to provide an additional COSS, which involves both time and costs, unless the Commission substantially agrees in principle with arguments put forth by ABATE in the instant case supporting the Average & Excess Demand methodology.<sup>1894</sup>

In rebuttal, regarding Ms. York's claim that the Average and Peak (A&P) allocator double counts gas consumption on the peak day, "once in the Average Demand component and again in the Peak Demand component", Mr. Krause states that Staff does not agree that the potential double counting is a problem.<sup>1895</sup> He adds that removal of the alleged double counting problem by removing the peak day from the average calculation would change the average by approximately one percent and passing this calculation

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<sup>1891</sup> 4 Tr 2177.

<sup>1892</sup> *Id.*

<sup>1893</sup> *Id.*

<sup>1894</sup> 4 Tr 2177-2178.

<sup>1895</sup> 4 Tr 1726.

through the allocator would have an extremely small impact on the allocator itself.<sup>1896</sup> He reiterates that Staff supports the use of the A&P methodology, one of the three most commonly used allocation methods for demand-related costs according to the NARUC Manual.<sup>1897</sup> He references what the NARUC Manual states about the A&P method.

This method reflects a compromise between the coincident and noncoincident demand methods. Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates cost to all classes of customers and tempers the apportionment of the costs between high and low load factor customers.<sup>1898</sup>

Mr. Krause asserts that Staff proposed using the A&P allocation method because of its nature as a compromise between the interests of high and low load factor customers, as well as the fact that it better reflects the classes' use of the system.<sup>1899</sup> He adds that because customer classes use the distribution system differently, it is reasonable to use an allocation method that combines how those disparate classes cause costs.<sup>1900</sup> He concludes that the Commission should continue to approve the use of the A&P allocator for distribution mains and related costs, as it is a reasonable allocation method which follows cost causative principles while balancing the interests of all of DTE's customers.<sup>1901</sup>

Mr. Revere states that in DTE's previous case, the Commission agreed with Staff that what was then deemed Staff's second alternate COS should be used to shape the

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<sup>1896</sup> 4 Tr 1727

<sup>1897</sup> 4 Tr 1728.

<sup>1898</sup> 4 Tr 1728, citing NARUC Manual, p. 27-28.

<sup>1899</sup> *Id.*

<sup>1900</sup> 4 Tr 1729.

<sup>1901</sup> 4 Tr 1730.

relative increases amongst transportation rate classes, and that a similar COS should be filed in its next rate case (the instant case).<sup>1902</sup> He adds that for the purposes of the instant case, Staff is not recommending the additional COSS be directly utilized, as it would be inappropriate to utilize the additional COSS directly, as recognizing the difference in costs in rates should be accompanied by a reexamination of the structure of rates.<sup>1903</sup> He states Staff has used the additional COSS, as modified for Staff's adjustments (Staff's Alternate COSS) as a guide to how revenue responsibility should be shifted between transportation schedules when adjustments must be made to maintain the current breakeven points.<sup>1904</sup> He states that he instructed Ms. Todd to keep each transportation schedule's share of the total transportation revenue requirement between the results of the COSS using the current methods of allocation and Staff's alternate COSS to the extent possible while conducting rate design.<sup>1905</sup> He asserts that this is a reasonable interim solution, which is a step toward the current state of Consumers Gas' transportation rate design.<sup>1906</sup> He states that Staff recommends DTE be required to include the additional COSS, updated for DTE's filing information, in future rate cases so that this method can continue to be utilized, and continue to explore the best way to modify rate design to directly utilize this alternate COSS.<sup>1907</sup>

In rebuttal, noting that Mr. Collins claims that distribution-other costs should only be allocated to XXLT based on the total class usage, as it was conceived as a transportation/high-pressure rate and only a small portion of volumes on the rate are at

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<sup>1902</sup> 4 Tr 1662, citing Case No. U-20940, Order, 12/9/2021, p. 210.

<sup>1903</sup> 4 Tr 1663.

<sup>1904</sup> *Id.*

<sup>1905</sup> 4 Tr 1664.

<sup>1906</sup> *Id.*

<sup>1907</sup> *Id.*

low-pressure, and claimed that the allocation to XXL T should be “corrected” to only be based on the low-pressure volumes, Mr. Revere counters that Mr. Collins ignored the fact that a substantial portion (in fact, a majority) of the volumes on XXL T are also taking service from the high-pressure distribution system.<sup>1908</sup> He states that it is Staff’s understanding that DTE does not have records on which pressure level the items in these Other Distribution Plant accounts are installed at or associated with, so the proportion is unknown.<sup>1909</sup> He adds that the proposed allocation method effectively assumes that the costs in these Other Distribution plant accounts are limited to low-pressure distribution but that no evidence was presented that would support this assumption.<sup>1910</sup> As such, he asserts that Mr. Collins’ proposal should be rejected.<sup>1911</sup>

Noting that Mr. Collins claims no knowledge that there has been a “showing that system load factor under the A&P methodology is the appropriate weighting mechanism,” Mr. Revere counters that using the load factor as a weighting mechanism is how the Average and Peak (A&P) method, one of the three “most commonly used demand allocations for natural gas distribution utilities” listed in the 1989 NARUC Gas Distribution Rate Design Manual (NARUC Manual), is described by the same manual, and thus, Mr. Collins’ statement should not be taken as a reason to abandon the long-standing approval of this method.<sup>1912</sup>

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<sup>1908</sup> 4 Tr 1666.

<sup>1909</sup> *Id.*

<sup>1910</sup> *Id.*

<sup>1911</sup> *Id.*

<sup>1912</sup> 4 Tr 1667.

Mr. Revere states that Staff does not agree with Mr. Collins that the XXLT increase be limited to the results of the 75/25 study, asserting that limiting the increase to XXLT based on an inappropriate method is unjustifiable and should be rejected.<sup>1913</sup>

Regarding Ms. York's statement that ABATE "would not oppose an equal percent increase across all customer classes for purposes of this case, so long as [DTE] commits to provide a CCOS using the AED allocation method as an alternative to the P&A CCOS in its next rate case," Mr. Revere asserts that Mr. York has not provided any support for an equal percent increase, nor any reason why it would be appropriate for such an increase being acceptable be tied to provision of a COS utilizing an allocator shown to be inappropriate.<sup>1914</sup>

Regarding Ms. York's statement that "the P&A method artificially produces smaller increases for lower-load factor customer classes than the utility's actual cost of service, relative to a purely demand-based allocation method," Mr. Revere counters that while the A&P method is described by the NARUC Manual as "tempering" costs and representing a compromise between high- and low-load factor customers, it does not follow that this compromise or tempering is "artificial" or introducing rate design concerns.<sup>1915</sup> He adds that Ms. York's preferred method is not more accurate or objective, but is aiming to inappropriately allocate fewer costs to the customer classes ABATE represents at the expense of recognizing how costs are caused.<sup>1916</sup>

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<sup>1913</sup> 4 Tr 1667-1668.

<sup>1914</sup> 4 Tr 1669-1670.

<sup>1915</sup> 4 Tr 1670-1671.

<sup>1916</sup> *Id.*

Regarding Ms. York's claims that the A&P allocator primarily allocates capacity costs on volume rather than peak demand, Mr. Revere counters that the A&P allocator (as calculated by DTE) allocates 64.236% of any cost it is applied to on peak day demand, and thus primarily allocates on peak day demand.<sup>1917</sup>

Regarding Mr. York's claim that the A&P allocation method is flawed as it "double counts" the average usage that occurs on the peak day, Mr. Revere counters that the A&E method proposed by ABATE fails to properly recognize usage of the system and the appropriate allocation of costs, uses a measure that has not been shown to have any connection to cost causation in the non-coincident peak (NCP), and breaks the link between system load factor, peak, and usage that the A&P method relies on.<sup>1918</sup> Mr. Revere states that the A&P method properly recognizes usage of the system and the appropriate allocation of costs, while the A&E methods fails to recognize that delivering the "average" amount of gas on a peak day (or during a class' NCP month) does not result in the same costs as on an average day and fails to recognize that average usage is really another way of incorporating throughput, or the entirety of gas used throughout the year, of which the average used on one of the days of the year represents an exceedingly small portion, thereby overcorrecting a problem that does not exist in the first place.<sup>1919</sup>

Mr. Collins states that overall rate revenues should equal actual cost of service.<sup>1920</sup> He adds that each major customer class should produce revenues equal to the cost of serving that particular class, no more and no less, which may require a rate increase for

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<sup>1917</sup> 4 Tr 1762. Citation omitted.

<sup>1918</sup> 4 Tr 1672.

<sup>1919</sup> 4 Tr 1672-1673.

<sup>1920</sup> 4 Tr 792.

some classes and a rate decrease for other classes.<sup>1921</sup> He states that rate levels should be modified so that each major class of service provides approximately the same rate of return.<sup>1922</sup> He adds that, in designing individual tariffs, the goal should also be to relate the rate design of each class to the cost of service so that each customer's rate tracks, to the extent practicable, the utility's cost of providing service to that customer.<sup>1923</sup>

Mr. Collins states that with respect to allocation, fixed cost should be allocated on a peak demand factor, variable cost should be allocated on a throughput factor and customer-related cost should be allocated on a per customer allocation factor.<sup>1924</sup>

Mr. Collins states that while he agrees with some of the allocations used by DTE, the Commission should take this opportunity to stop the over-allocation of cost to the Rate XXLT double-extra large transportation customers, as failing to correct this inequity will result in DTE's rates becoming even less competitive.<sup>1925</sup> He adds that he disagrees with the allocation of distribution-other to the Rate XXLT class based on total class usage and the use of the A&P method to allocate fixed costs of the gas delivery system, the elimination of which would make rates more reflective of cost and would make Michigan more attractive to energy-intensive industries through more competitive gas transportation rates.<sup>1926</sup>

Mr. Collins states that the system must be designed to deliver gas to the load that occurs on the coldest winter day, also known as the design peak day demand.<sup>1927</sup> Noting

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<sup>1921</sup> Id.

<sup>1922</sup> Id.

<sup>1923</sup> 4 Tr 792-793.

<sup>1924</sup> 4 Tr 795.

<sup>1925</sup> 4 Tr 796.

<sup>1926</sup> Id.

<sup>1927</sup> Id.

that the average throughput is 881,773 Mcf and the design peak day demand is 2,465,544 Mcf., he asserts that a system designed to serve 881,773 Mcf is clearly inadequate to serve the winter peak day demand of 2,465,544 Mcf.<sup>1928</sup> He adds that allocating fixed delivery system cost on average annual throughput over-allocates cost to high load factor customers and under-allocates cost to low load factor customers that require the system deliverability to meet the peak load during the coldest period.<sup>1929</sup>

Mr. Collins states that more throughput without an increase in demand makes the system more efficient and reduces overall costs to all ratepayers.<sup>1930</sup> He asserts that the A&P formula unfairly increases the allocation on throughput and punishes the higher load factor classes that are responsible for increasing the efficiency of the system by increasing their costs.<sup>1931</sup>

Mr. Collins states that the peak day demand method is far superior to the A&P approach for allocating based on actual cost causation.<sup>1932</sup> He adds that the peak day demand is the main driver in the planning activities for system design and hence, the cost of constructing and operating a system that can reliably serve 2,465,544 Mcf on the coldest winter days.<sup>1933</sup> He states that a system designed to serve the average daily throughput of 881,773 Mcf could serve only 35.8% of the load during the cold winter peak period.<sup>1934</sup>

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<sup>1928</sup> 4 Tr 797-798.

<sup>1929</sup> 4 Tr 798.

<sup>1930</sup> Id.

<sup>1931</sup> Id.

<sup>1932</sup> Id.

<sup>1933</sup> Id.

<sup>1934</sup> Id.

Mr. Collins states that NARUC recognizes that distribution mains should be allocated to customer classes based on: (1) design peak day demands for the demand component; and (2) the number of customers for the customer component.<sup>1935</sup> He adds that the NARUC Gas Distribution Rate Design Manual provides that demand or capacity costs are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage.<sup>1936</sup> He states that in Order 636, the Federal Energy Regulatory Commission (“FERC”) endorsed the SFV cost methodology, which allocates fixed pipeline cost 100% on a demand basis.<sup>1937</sup> He asserts that distribution main costs not classified as customer-related on DTE’s system should be treated as demand-related costs to achieve the goals and benefits outlined by FERC and in accordance with NARUC guidance, and that the peak day demand method allows this to be done.<sup>1938</sup>

Mr. Collins states that he used DTE’s model to perform a peak day demand cost of service study and also corrected the allocation of distribution-other to the Rate XXLT class.<sup>1939</sup> He adds that the results of this study indicate that transportation customers are providing revenues significantly in excess of their cost of service.<sup>1940</sup> He notes that this design peak day demand study supports a sizeable revenue decrease of 45.0% to the Rate XXLT class, at proposed rate levels.<sup>1941</sup>

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<sup>1935</sup> 4 Tr 799-800, referencing NARUC Manual, Gas Distribution Rate Design, June 1989.

<sup>1936</sup> 4 Tr 800, citing NARUC Manual, Gas Distribution Rate Design, June 1989, pp. 23-24.

<sup>1937</sup> *Id.*, citing FERC 30 Order 636, Final Rate Issued April 8, 1992.

<sup>1938</sup> 4 Tr 801.

<sup>1939</sup> 4 Tr 801; Ex, MPL-2.

<sup>1940</sup> 4 Tr 802.

<sup>1941</sup> *Id.*

Mr. Collins states that although he believes the design peak day demand study is the most reflective of cost causation, he performed a “75/25” study as an alternative method to correct the unfairness of the A&P study.<sup>1942</sup> He adds that the 75/25 study adds stability and certainty to the cost allocation method and is consistent with most electric cost of service studies approved by the Commission, although is not as cost based as the design peak day demand approach.<sup>1943</sup> He asserts that based on the 75/25 allocation method, Rate XXLT be decreased by 5.8% to be reflective of cost.<sup>1944</sup>

Mr. Collins recommends that any increase to Rate XXLT transportation customers be limited to a maximum of those set forth in the corrected 75/25 study as an intermediate step that substantially addresses the anti-competitive and inefficiency biases inherent in DTE's A&P methodology.<sup>1945</sup>

Regarding the Rate XXLT rate design, Mr. Collins asserts that it is important to recognize that although Rate ST, Rate LT, Rate XLT, and Rate XXLT each are treated separately in the cost of service study, they are all contained in one transportation rate which uses breakeven points based on usage to provide target rate levels.<sup>1946</sup> He adds that Rate XXLT is unique in that seven customers account for 26.3% of total DTE sales (throughput) and operate at a highly efficient 85.9% load factor.<sup>1947</sup>

Regarding the alternate cost of service study filed by DTE, Mr. Collins states that the alternate study is a significant departure from past practice and produces an

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<sup>1942</sup> Id.; Ex. MPL-4.

<sup>1943</sup> Id.

<sup>1944</sup> 4 Tr 805.

<sup>1945</sup> 4 Tr 805.

<sup>1946</sup> Id.

<sup>1947</sup> Id.; Ex. MPL-6.

extremely harsh impact on rates for customers such as those on Rate XXL<sup>1948</sup>. He adds that for a customer such as Michigan Power LP which is served and metered at the transmission service level, the alternative study produces completely erroneous results.<sup>1949</sup>

In rebuttal, Mr. Collins notes that Staff's filing has reduced DTE's overall \$265.5 million requested increase to \$175.7 million, and on the basis of the \$175.7 million level, Staff's proposed increase to Rate XXL is \$9.9 million or 31.5%.<sup>1950</sup> he asserts that this in a sharp contrast to the DTE proposed increase to Rate XXL of \$4.6 million or 14.7% based on the overall \$265.5 million revenue increase.<sup>1951</sup> He asserts that Staff's proposal is unreasonable as Staff is proposing to change the revenue responsibility of the largest transportation class and changes the results of the A&P study for the revenue responsibility of the largest transportation customers from the previously approved A&P study methodology.<sup>1952</sup> Noting that Staff's cost of service model includes a revenue distribution to classes based on previously approved methodology by DTE and Staff, Mr. Collins asserts that based on the Staff A&P study, the increase to Rate XXL is \$1,522 million or 4.86%.<sup>1953</sup> He adds that Staff adds significantly more cost to Rate XXL based on the Alternative 2 (Hi-Lo) study which resulted in changing the rate increase from \$1,522 million or 4.86% to \$9.879 million or 31.54%.<sup>1954</sup>

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<sup>1948</sup> 4 Tr 8-7-808

<sup>1949</sup> 4 Tr 808.

<sup>1950</sup> 4 Tr 814; Ex. S-6 (rev).

<sup>1951</sup> *Id.*

<sup>1952</sup> *Id.*

<sup>1953</sup> 4 Tr 815; ex. MPL-7.

<sup>1954</sup> *Id.*; Ex. S-6.0, Sch. F-2 (rev).

Mr. Collins states that if despite this serious shortcoming, the Commission adopts Staff's approach, then only the customers using the distribution system should pay the increased costs associated with the distribution allocation to Rate XXLTL as proposed by Staff.<sup>1955</sup> He asserts that using Staff's revenue requirements and the A&P study does not adequately provide a cost based transmission level rate.<sup>1956</sup> He states that the correct Rate XXLTL for transmission level service and the associated rate design are provided on revised Ex. MPL-9 and MPL-10.<sup>1957</sup>

In rebuttal, Mr. Krause states that both ABATE and MPLP stress the design of the main system and link that to cost causation.<sup>1958</sup> He asserts that Staff disagrees with their perspective, asserting that while the way customers cause costs on gas mains does depend on designing the system to meet peak day demand, in part, it also depends on usage.<sup>1959</sup> He adds that it has not been shown how exactly costs change with demand, with a number of costs associated with designing and constructing the system may vary little with demand (trenching, boring, etc.) or vary more on geography (length of main, etc.).<sup>1960</sup>

Regarding ABATE's assertion that the Average and Peak (A&P) allocator double counts gas consumption on the peak day, "once in the Average Demand component and again in the Peak Demand component", Mr. Krause counters that Staff does not agree that the potential double counting is a problem, with the average being calculated based on 365 days of class gas consumption and only a portion of the peak day could be

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<sup>1955</sup> Id.

<sup>1956</sup> 4 Tr 818.

<sup>1957</sup> Id.

<sup>1958</sup> 4 Tr 1725.

<sup>1959</sup> 4 Tr 1726.

<sup>1960</sup> Id.

considered double counted.<sup>1961</sup> He asserts that the average could be determined using the 364 days other than the peak day, with the result being that the average gas on the peak day would not be double counted.<sup>1962</sup> He adds that the average for the year would not likely move much because although you would be removing the peak day from the calculation the other 364 data points would likely dominate the calculation.<sup>1963</sup> Thus, he concludes that removal of the alleged double counting problem by removing the peak day from the average calculation would change the average by approximately 1%, such that passing this calculation through the allocator would have an extremely small impact on the allocator itself.<sup>1964</sup> Noting that ABATE asserts that the Design Day Demand is preferred to the A&P method, Staff continues to support A&P, which is one of the three most commonly used allocation methods for demand-related costs according to the NARUC Manual.<sup>1965</sup> He states:

Staff proposed using the A&P allocation method because of its nature as a compromise between the interests of high and low load factor customers, as well as the fact that it better reflects the classes' use of the system. High and low load factor customers use the distribution system differently, so it is not fair to allocate the costs for using that system as if it were used for a single purpose: to meet designed peak demand. Because customer classes use the distribution system differently, it is reasonable to use an allocation method that combines how those disparate classes cause costs.<sup>1966</sup>

He adds that in the past, the Commission has properly recognized that there are sound reasons for allocating some portion of demand-related costs on the basis of non-peak throughput.<sup>1967</sup> He also adds that Staff does not support ABATE's proposal to use a

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<sup>1961</sup> 4 Tr 1726.

<sup>1962</sup> Id.

<sup>1963</sup> Id.

<sup>1964</sup> Id.

<sup>1965</sup> 4 Tr 1728.

<sup>1966</sup> 4 Tr 1728-1729.

<sup>1967</sup> 4 Tr 1729, citing Case No. U-10150, Order, October 28, 1993, p. 96.

Design Day Demand method to allocate mains and other costs, asserting that the natural gas distribution system, both fixed in the short-term and variable in the long-term, is simultaneously planned to operate on peak days and used by customers every day.<sup>1968</sup>

Mr. Krause disagrees with Mr. Collins's characterization of fixed costs.<sup>1969</sup> He adds that although capacity is designed and built to handle peak, it is also true that some of that capacity is used whenever gas is delivered, therefore it is reasonable to collect for some portion of capacity on throughput.<sup>1970</sup>

Regarding MPLP's assertion that the A&P allocation method is not the appropriate means for allocating fixed distribution costs, Mr. Krause counters that it is Staff's position that the A&P allocator is a reasonable method of allocating costs that were classified as demand related.<sup>1971</sup> He adds Staff also disagrees with MPLP's interpretation of the NARUC Manual, and is unconvinced by MPLP's attempt to apply an order from a federal regulatory body to a case before the Michigan Public Service Commission.<sup>1972</sup> He asserts that Staff has consistently put forward, and the Commission has repeatedly approved, a position consistent with the NARUC Manual that only those portions of distribution plant that vary directly with the number of customers should be classified as customer-related.<sup>1973</sup> He adds that distribution mains, not varying directly with the number of customers, should be classified as demand-related.<sup>1974</sup> He asserts that Staff supports the use of the A&P methodology, one of the three most commonly used allocation methods

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<sup>1968</sup> 4 Tr 1730.

<sup>1969</sup> 4 Tr 1732.

<sup>1970</sup> Id.

<sup>1971</sup> 4 Tr 1733.

<sup>1972</sup> Id.

<sup>1973</sup> 4 Tr 1735.

<sup>1974</sup> Id.

for demand-related costs according to the NARUC Manual, of which A&P method the NARUC Manual states:

“This method reflects a compromise between the coincident and noncoincident demand methods. Total demand costs are multiplied by the system’s load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates cost to all classes of customers and tempers the apportionment of the costs between high and low load factor customers.”<sup>1975</sup>

Mr. Krause asserts that in the past, the Commission has properly recognized that there are sound reasons for allocating some portion of demand-related costs on the basis of non-peak throughput.<sup>1976</sup> Thus, he concludes that the Commission should continue to approve the use of the A&P allocator for distribution mains and related costs, asserting it is a reasonable allocation method which follows cost-causative principals while balancing the interests of all of DTE’s customers.<sup>1977</sup>

Mr. Krause does not support Mr. Collins’ COSS using peak day to allocate “fixed” costs, asserting that the natural gas distribution system, both fixed in the very short-term and variable in the long-term, is simultaneously planned to operate on peak days and used by customers every day.<sup>1978</sup> He adds that Staff does not support Mr. Collins’ alternative COSS that sets the throughput component of the A&P allocator to 25%, asserting that the currently approved A&P allocator correctly accounts for the total use of the system: on peak day and the remaining 364 days of the year.<sup>1979</sup> He states that the 75-25 method of allocation of electric production costs is not analogous to the proper

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<sup>1975</sup> 4 Tr 1736, citing NARUC Manual, p. 27-28.

<sup>1976</sup> 4 Tr 1738, citing Case No. U-10150, Order, October 28, 1993, p. 96.

<sup>1977</sup> 4 Tr 1738.

<sup>1978</sup> 4 Tr 1738-1739.

<sup>1979</sup> 4 Tr 1739.

allocation of natural gas delivery costs, asserting that the particular method is used for allocating production costs in electric cost of service studies, which is not only a different utility industry, but also a completely different category of costs, and with the production of electricity involving a cornucopia of inputs and assumptions that are unassociated with the delivery of natural gas.<sup>1980</sup> He adds that Mr. Collins does not present evidence to support his claim that the A&P method lacks validity.<sup>1981</sup>

### **Alternate COSS**

Mr. Krysinski states that DTE has prepared an Alternate COSS which uses the same methodology as the second alternate cost of service study provided by DTE in its last gas rate case, updated for costs in the instant case, as well as updated supplemental studies.<sup>1982</sup> He adds that the Alternate COSS utilizes the same costs as DTE Gas's Proposed COSS and has been modified by splitting distribution main plant and IRM Main Replacement Program into high-pressure and low-pressure costs.<sup>1983</sup> He states that the high-pressure distribution main costs are allocated to customers taking service from DTE's high-pressure and low-pressure distribution system, while excluding volumes taken from the transmission system, and that low-pressure distribution main costs are allocated to customers taking service from the low-pressure distribution system only.<sup>1984</sup>

In rebuttal, Mr. Krause disagrees with Mr. Koeppel's statement that "in 2016, the Michigan legislature killed net metering and ordered the Commission to replace it with the inflow-outflow tariff," asserting that Mr. Koeppel mischaracterizes the events as they took

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<sup>1980</sup> Id.

<sup>1981</sup> 4 Tr 1739-1740.

<sup>1982</sup> 4 Tr 2162; Ex. A-24, Sch. N1. Revised.

<sup>1983</sup> 4 Tr 2162-2163.

<sup>1984</sup> 4 Tr 2163.

place.<sup>1985</sup> He adds that the Legislature ordered the replacement of net metering with a distributed generation tariff based on cost-of-service, which the Commission determined should be the inflow--outflow tariff.<sup>1986</sup>

Noting Mr. Koeppel recommends better compensation rates for distributed generation (DG) for all and specific incentives for communities with implementation barriers to assure equitable, system-wide distribution of DG, Mr. Krause counters that the directive from the Legislature on DG tariffs is to make them cost-of-service based, and Mr. Koeppel's recommendation has not been shown to accomplish that.<sup>1987</sup> Noting that DTE Gas Company does not have a DG tariff, he asserts that any discussion of the appropriate DG tariff for DTE Electric Company is inappropriate in this proceeding.<sup>1988</sup>

Staff recommends changes to DTE's proposed rate design, using the revenue requirements from Staff's proposed cost-of-service study (COSS), the residential GS-1, and school customer charges recommended by Staff, as well as various data within the COSS, and used them as the basis for recalculating rate design.<sup>1989</sup> Ms. Todd states that Staff recommends setting the rates for General Service customers as close and reasonably possible to the recovery amount for the cost to serve those customers, while also maintaining the economic break-even points between the individual General Service rate schedules.<sup>1990</sup> Regarding the General Service customer and distribution charges, she states that Staff takes no issue with DTE's recommend customer charges for rate

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<sup>1985</sup> 4 Tr 1724.

<sup>1986</sup> Id.

<sup>1987</sup> 4 Tr 1725.

<sup>1988</sup> Id.

<sup>1989</sup> 4 Tr 1640.

<sup>1990</sup> 4 Tr 1640-1641.

schedule GS-1 set to \$50.00 and rate schedule GS-2 set to \$925.00.<sup>1991</sup> She adds that in attempting to maintain the break-even point and being mindful of rate design targets, Staff recommends distribution charges of \$4.3332/Mcf for GS-1 and \$3.5832/Mcf for GS-2.<sup>1992</sup>

Ms. Todd states that regarding rate design for the School Service Rate S, Staff recommends that rates for Rate S be set to recover the cost to serve those customers, while also maintaining the economic break-even point between Rate S and GS-1, and as such, Staff proposes the customer charge for Rate S of \$270.00 and the distribution charge be set at \$2.9118Mcf.<sup>1993</sup>

Ms. Todd states that regarding Customer and Distribution Charges for Transportation schedules, Staff recommends that the customer charge for rate schedule ST be set at \$2,780, which maintains the break-even point between rates ST and LT customers as well as the remaining transportation customers.<sup>1994</sup> She adds that the proposed customer charges for the other transportation customers are: \$4,950 for LT, \$14,000 for XLT, and \$198,800 for XXLT, which are designed so the economic break-even points between rate schedules can be maintained.<sup>1995</sup> She states that Staff aimed for balanced increases in revenue from both the customer charge and distribution charge, and considered the percentage share to be collected from each transportation schedules based on Staff's Alternate COSS.<sup>1996</sup>

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<sup>1991</sup> 4 Tr 1641; Ex. S-6.0, Sch. F3, p. 2.

<sup>1992</sup> Id.

<sup>1993</sup> Id.; Ex. S-6.0, Sch. F3, p. 3.

<sup>1994</sup> 4 Tr 1642; Ex. S-6.0, Sch. F3, p. 4.

<sup>1995</sup> Id.

<sup>1996</sup> Id.

Ms. Todd states that Staff recommends the following distribution charges for the transportation customers: \$1.4906/Mcf for ST, \$1.1417/Mcf for LT, \$0.9107/Mcf for XLT, and \$0.2870/Mcf for XXLTL.<sup>1997</sup>

Regarding Mr. Cebulko's statement that Michigan legislation states that the Commission shall prioritize certain goals including: "Equitable access to energy efficiency . . . clean energy technologies," and "Minimization of harm and prioritization of benefits in communities consisting predominately of minorities or households below the poverty line where factors . . . may act cumulatively to affect public health and the environment and contribute to persistent disparities, " Mr. Revere counters that the version of the bill passed by the Senate, the version passed by the House, the Senate-concurred version, and the Governor-signed public act (2023 PA 231) all lacked the quoted language.<sup>1998</sup>

This PFD agrees with DTE and Staff that the Commission has long-held its approval of using two demand / capacity allocation methods as approved in DTE's last five gas rate cases, including Case No. U-20940, with the Average and Peak (A&P) allocation method being approved for allocating functionalized transportation costs and non-customer related distribution costs, and for storage costs, a blended method of 50% cost allocation on the Peak method and 50% cost allocation on the percentage of storage capacity. Moreover, this PFD finds that neither ABATE nor MPLP have offered compelling reasons why the Commission should adopt a changed approach to its allocation methods. Indeed, this PFD finds that the evidence and arguments put forth by ABATE and MPLP in this case have been effectively rebutted by DTE and Staff here, and that the same or

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<sup>1997</sup> Id.

<sup>1998</sup> 4 Tr 1673.

similar arguments have been consistently rejected by the Commission in the past. See, e.g., Case No. U-20940, Order, December 9, 2021, p. 190 – 210. Thus, this PFD recommends that the Commission again adopt the allocation method utilized by DTE and Staff.

This PFD agrees with Staff modification of DTE's calculation of customer charges using a combination of historical and projected expenses as utilizing only historical costs ensures that DTE's method of spreading projected costs does not include costs that are inappropriate for inclusion in the customer charge. Thus, this PFD recommends that the Commission adopt Staff's recommendations of the following customer charges: Residential - \$14.50, School - \$270.00, and GS-1 \$50.00, with all other customer charges being determined by rate design. This PFD notes that Staff's proposed Residential charge of \$14.50 coincides with the alternative charge proposed by the Attorney General.

This PFD agrees with Staff's recommendation that the Commission require DTE to continue filing the alternate COS in future cases. As Staff asserts, including the additional COSS, updated for DTE's filing information, in future rate cases will allow this method to continue to be utilized and continue to explore the best way to modify rate design to directly utilize this alternate COSS. In addition, this PFD disagrees with DTE's proposal whereby the Commission allows DTE to reuse workpapers provided in this instant case to prepare the Alternate COSS in DTE's next rate case. As Staff points out in its brief, this approach would not require an update of all data necessary for the alternate COS to be useful. Thus, this PFD recommends that the Commission require DTE to continue to file the alternate COS in future cases.

## **Other Issues**

### **Revenue Decoupling Mechanism**

DTE states that revenue decoupling is a regulatory mechanism whereby revenue differences are trued-up on a periodic basis and flowed back to or recovered from customers as adjustments to rates so that the utility's revenues match the allowed revenue requirement as established in the utility's most recent general rate case.<sup>1999</sup> DTE states that RDM eliminates the negative financial impact from the loss of energy sales resulting from EWR programs.<sup>2000</sup>

DTE states that current RDM -- approved by the Commission in its December 9, 2021, order in Case No. U-20940 -- is designed as a "simple revenue tracker" reconciling Case No. U-20940 distribution revenue with actual weather normalized distribution revenue (both excluding GCR revenues, surcharges and the customer charges).<sup>2001</sup> DTE adds that the RDM is limited by a revenue cap set at 150% of the legislated EWR targets, resulting in a current RDM cap of 2.25%.<sup>2002</sup> The current RDM will terminate when DTE implements new rates by Commission order in this proceeding.<sup>2003</sup> DTE states that the current RDM excludes large general service customers (General Service Rate, GS-2) and End-User Transportation (EUT) customers from the RDM calculation.<sup>2004</sup>

DTE is proposing to continue the RDM approved in Case No. U-20940 as a "simple revenue tracker" that reconciles Case No. U-21291 distribution revenue (excluding GCR revenues, surcharges and customer charges), with actual weather normalized distribution

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<sup>1999</sup> 4 Tr 1854.

<sup>2000</sup> Id.

<sup>2001</sup> 4 Tr 1855.

<sup>2002</sup> Id.

<sup>2003</sup> Id.

<sup>2004</sup> Id.

revenue (excluding GCR revenues, surcharges and the customer charges).<sup>2005</sup> DTE proposes that the first reconciliation period begin October 1, 2025, which is the first month following the end of the projected test year in this case.<sup>2006</sup>

FLO argues that the Commission should reject the RDM.<sup>2007</sup> Mr. Koepfel asserts that the RDM extends the mid-transition -- the period during which energy supply is constrained by a goal of reducing or eliminating greenhouse gas emissions and comprised of fossil carbon-emitting systems and zero-carbon systems -- by disincentivizing customer energy waste reduction.<sup>2008</sup> Noting that DTE asserts that RDMs are useful tools for encouraging utilities to support and invest in reducing energy use -- by separating revenue from sales, utilities are freed from the desire to increase usage to boost their revenues -- he argues that revenue decoupling does not appear to have been effective with DTE.<sup>2009</sup> He notes that in Case No. U-21576, DTE sought to reconcile 2023 revenue using the approved RDM, and that in this case, DTE shows that cumulative weather normalized volumes and revenues for the period exceeded the projections from Case No. U -20940, leading to a credit.<sup>2010</sup> He asserts that if the purpose of the RDM is to encourage energy waste reduction, it seems that it has been ineffective in doing so.<sup>2011</sup> He notes that The statements in DTE Gas's SEC filings and Gas Delivery Plan demonstrate that DTE's explicit strategy is to expand gas usage to new customers and within their existing customer base.<sup>2012</sup>

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<sup>2005</sup> 4 Tr 1856.

<sup>2006</sup> Id.

<sup>2007</sup> 4 Tr 1040.

<sup>2008</sup> 4 Tr 1029.

<sup>2009</sup> 4 Tr 1030. Citation omitted.

<sup>2010</sup> 4 Tr 1030-1031. Citation omitted.

<sup>2011</sup> 4 Tr 1031.

<sup>2012</sup> Id.

Mr. Koeppel states that an RDM that is effective in reducing energy use will cause customers to experience higher surcharges as a result of effective utilization of EWR, because the RDM is expressly designed to cure DTE Gas's losses from lower energy demand through a higher surcharge.<sup>2013</sup> He adds that to whatever extent an RDM removes DTE Gas's "disincentive" to encourage EWR, the incentive for customers to take advantage of it is removed in precisely equal measure.<sup>2014</sup> He asserts that the overall effect of the RDM (and IRM) is to encourage DTE to overspend on capital while being insulated from the effect of customers choosing to use less gas.<sup>2015</sup>

DTE counters that Michigan statutory authority directs that the Commission give deference to a utility's RDM proposal.<sup>2016</sup> DTE asserts that RDMs are broadly authorized under that statute, which must be applied as written, and the Commission is directed to give deference to a utility's proposal.<sup>2017</sup> DTE adds that DTE' Gas's proposed RDM is reasonable and should be adopted as such.<sup>2018</sup> DTE asserts that it is proposing the same RDM methodology that this Commission approved in DTE's last rate case, and approved in DTE's last five rate cases.<sup>2019</sup> DTE adds that it is projecting losses due to reductions in usage per customer driven by DTE's EWR program, and FLO has not presented any evidence to the contrary.<sup>2020</sup>

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<sup>2013</sup> 4 Tr 1032.

<sup>2014</sup> Id.

<sup>2015</sup> 4 Tr 1033.

<sup>2016</sup> DTE initial brief, p. 139.

<sup>2017</sup> Id. Citations omitted.

<sup>2018</sup> Id.

<sup>2019</sup> Id.

<sup>2020</sup> Id., p. 140.

This PFD finds DTE’s proposed RDM to be reasonable and consistent with the RDM approved in prior rate cases. Thus, this PFD recommends that the Commission adopt DTE’s proposed RDM.

### **Leak Backlog**

Mr. Kehoe states that in 2021, DTE Gas remediated 5,439 leaks with approximately 5,303 new incoming leaks, which resulted in a balance at the end of 2022 of 856 leaks.<sup>2021</sup> He adds that for 2024, DTE Gas forecasts 6,031 new incoming leaks and plans to remediate 6,703 leaks during the year resulting in a year-end backlog of 1,250 leaks.<sup>2022</sup>

### **Demand Response**

Mr. Decker states that DTE piloted two residential Gas DR programs, Smart Savers and Energy Action Days, and one Commercial Program.<sup>2023</sup> He adds that the Smart Savers Gas pilot targeted combo and gas only residential customers who already had a Wi-Fi enabled smart thermostat installed, whereby participants allowed DTE to adjust their thermostat by up to 4 degrees during events.<sup>2024</sup> He states that the Energy Action Days program aimed to use behavioral science to encourage customers to reduce their natural gas use during times of high demand.<sup>2025</sup> He adds that DTE also designed a pilot to target larger customers (e.g. customers who take their gas service under rate GS-1, GS-2 or the S-rate) to understand how these customers would respond to a demand response program.<sup>2026</sup> He states that the results from the Smart Saver Gas events

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<sup>2021</sup> 4 Tr 2042; Ex. A-20, Sch. J1.

<sup>2022</sup> 4 Tr 2043, Table 25.

<sup>2023</sup> 2 Tr 111.

<sup>2024</sup> *Id.*

<sup>2025</sup> *Id.*

<sup>2026</sup> 2 Tr 112.

showed load reduction, while DTE did not observe any significant gas reductions across any of the events under the other two programs.<sup>2027</sup> Thus, DTE concluded that it was clear that the demand response programs were not effective and thus that it would not be reasonable or prudent to propose additional demand response programs.<sup>2028</sup> He states that DTE deferred \$2.6 million of demand response costs over the two-year period, and that at this time based on the learnings, DTE has no plans to move forward with gas DR programs.<sup>2029</sup>

MNSC asserts that DTE should continue offering the Smart Savers pilot program as DTE's evaluation showed that its pilot reduced large amounts of gas usage during gas demand events.<sup>2030</sup> Ms. Napoleon states that she found that DTE's own assessment of gas savings during peak hours does not support its recommendation to discontinue the Smart Savers pilot program, noting that this pilot program led to a 36% to 72% reduction in gas use during the past five gas events.<sup>2031</sup> She asserts that while the overall gas consumption for the participants during one of the five peak day events (January 28) increased slightly – she asserts that that event was an outlier caused by snapback effects -- for all other days, the pilot saved considerable amounts of gas during the peak events. She adds that DTE did not assess the cost-effectiveness of any of the demand response pilot programs, as DTE's evaluation showed that its pilot reduced large amounts of gas usage during gas demand events.<sup>2032</sup> Ms. Napoleon states that to increase the success

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<sup>2027</sup> 2 Tr 112-115.

<sup>2028</sup> 2 Tr 116.

<sup>2029</sup> 2 Tr 115.

<sup>2030</sup> 4 Tr 933.

<sup>2031</sup> 4 Tr 932; Ex. MEC-27.

<sup>2032</sup> 4 Tr 933; Ex. MEC-28.

rate, DTE should explore and evaluate ways to reduce snapback effects.<sup>2033</sup> She also recommends that the Commission require DTE to evaluate the cost-effectiveness of demand response as an alternative to conventional gas pipeline investments, asserting that it is the industry-standard practice to evaluate cost-effectiveness of any demand-side resources including demand response when they are promoted or examined as a ratepayer-funded program as DTE did when it evaluated the cost-effectiveness of its Energy Waste Reduction program.<sup>2034</sup>

CEO also argues that DTE should not abandon demand response programs.<sup>2035</sup> Mr. Cebulko states that DTE failed to set clear objectives for its demand response pilots, which is a significant driver as to why DTE concluded the programs were not successful.<sup>2036</sup> He asserts that DTE does not identify or explain what “effectiveness of gas demand response as a requirement of the Commission” means, nor explain what understanding it was seeking from the pilots.<sup>2037</sup> He states that did not conduct a cost-benefit analysis on any of the pilots either before starting the pilots nor after the conclusion of the pilots.<sup>2038</sup> He notes that DTE did not track the costs of the individual pilot programs but rather it tracked the costs of the three programs in the aggregate, such that DTE does not know the costs of any individual pilot.<sup>2039</sup> He adds that understanding the individual pilot program costs is necessary for determining if a pilot was successful.<sup>2040</sup>

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<sup>2033</sup> 4 Tr 933. Snapback is a well-known phenomenon whereby after the event, customer demand quickly rises. 4 Tr 748.

<sup>2034</sup> 4 Tr 934.

<sup>2035</sup> 4 Tr 739.

<sup>2036</sup> 4 Tr 740.

<sup>2037</sup> 4 Tr 742.

<sup>2038</sup> 4 Tr 743.

<sup>2039</sup> 4 Tr 744.

<sup>2040</sup> *Id.*

Mr. Cebulko states that the limited data DTE evaluated in their presentation shows that the Smart Savers pilot successfully reduced customer usage during the events.<sup>2041</sup>

Mr. Cebulko recommends the Commission reject DTE's request to recover the \$2.6 million in deferred demand response costs, as DTE did not put forth a reasonable effort towards developing and evaluating demand response programs.<sup>2042</sup> He also recommends the Commission require DTE to commit the necessary resources to develop a robust demand response program, which DTE should complete by July 2025 or prior to filing its next general rate case, whichever comes first.<sup>2043</sup>

DTE counters that DTE's pilot programs had the clear objective of observing a reduction in demand during high demand periods and to observe high levels of customer engagement in order to determine interest in such offerings.<sup>2044</sup> DTE asserts that these pilots were well thought out and engaged various groups of customers, and the decision to discontinue them was a result of the actual performance of the pilots.<sup>2045</sup>

This PFD agrees with DTE that it should be allowed to recover the \$2.6 million in deferred demand response costs, as DTE has supported that these costs were prudent and reasonable. However, this PFD agrees with MNSC and CEO that the Commission should direct DTE to continue offering the Smart Savers pilot program as DTE's evaluation showed that this pilot reduced large amounts of gas usage during gas demand events. Moreover, DTE has not offered any contrary evidence nor offered any explanation for why its data does not support that significant amounts of gas usage were reduced.

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<sup>2041</sup> 4 Tr 748; Ex. CEO-41.

<sup>2042</sup> 4 Tr 751.

<sup>2043</sup> 4 Tr 752.

<sup>2044</sup> DTE initial brief, p. 144.

<sup>2045</sup> *Id.*

Indeed, this PFD notes that neither of DTE’s two witnesses who stated that DTE decided to discontinue the pilots, after having “reviewed” and “analyzed” the results, offers any characterization or quantifiable assessment of the “results” which would support the discontinuance of the pilots.<sup>2046</sup> As the Commission has identified the importance of demand response during energy emergencies and has encouraged the development or expansion of natural gas DR programs<sup>2047</sup>, this PFD recommends that the Commission require DTE to continue this program to further assess its effectiveness.

### **Advanced Metering Infrastructure Benefits Reporting**

Mr. Abona states that from January 1, 2023, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$3.4 million of advanced metering infrastructure capital expenditures.<sup>2048</sup> He adds that on average, DTE Gas expects its 2023-2025 routine AMI/AMR expenditures to be \$4.2 million lower per year than the 2018-2022 \$5.3 million five-year average.<sup>2049</sup>

Mr. Kehoe states that as of August 2023, DTE Gas has installed 716,507 Advanced Metering AMI gas modules and 641,750 Advanced Metering AMR gas modules.<sup>2050</sup> He adds that DTE Gas is projected to complete the majority of the AMI project at the end of 2023, with the remaining non AMI/AMR meters, ~36,000, primarily

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<sup>2046</sup> See, 2 Tr 116; 4 Tr 1862.

<sup>2047</sup> See, Michigan Public Service Commission, “Michigan Statewide Energy Assessment, Final Report,” September 11, 2019. (“Given the pivotal role that DR can play during energy emergencies, the development or expansion of natural gas DR programs should be analyzed.”) 4 Tr 740.

<sup>2048</sup> 3 Tr 357; Ex. A-12, Sch. B5.1

<sup>2049</sup> Id.

<sup>2050</sup> 4 Tr 2044.

to be resolved via other programs.<sup>2051</sup> He states that by year end 2023, DTE Gas will have 98% of total meter installs with Advanced Metering capabilities.<sup>2052</sup>

Mr. Kehoe states that Gas AMI benefits for the test period, October 2024 through September 2025, are estimated to be \$13.8 million.<sup>2053</sup>

### **Accounting Requests**

DTE is requesting to recover a number of deferred expenses, along with new and continued deferrals of expenses, including a) Recovery of deferred shared asset expenses and continuation of the shared asset expense deferral; b) Recovery of deferred incentive compensation expenses and continuation of the incentive compensation tracker; c) Recovery of deferred DR expenses; d) Recovery of deferred TCARP expenses; e) Continuation of the LIA tracker; f) Continued deferral of costs for the low-income stability plan; g) Continued deferral of OPEB and Pension costs; and h) Deferral for the projected increase in LDAR costs.<sup>2054</sup> None of these requests were opposed. As such, the Commission should approve the accounting requests.

### **Accounting for the Infrastructure Recovery Mechanism**

Ms. Uzenski states that the Commission order in Case No. U-18999 required the IRM surcharges be terminated effective when new base rates superseding the IRM are implemented.<sup>2055</sup> She adds that all related net plant forecasted through December 2024 is reflected in base rates in this case.<sup>2056</sup> She states that the IRM capital expenditures and plant balances, the related costs and revenues, and the related debt and equity are

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<sup>2051</sup> Id.

<sup>2052</sup> 4 Tr 2045.

<sup>2053</sup> Id.; Ex. A-21, Sch. K1.

<sup>2054</sup> DTE initial brief, p. 146.

<sup>2055</sup> 4 Tr 2329

<sup>2056</sup> Id.

excluded from her projected financial statements for the periods after December 2024 because DTE is proposing to recover those costs in a new IRM surcharge.<sup>2057</sup>

### **Responsibly Sourced Gas**

Mr. Decker states RSG is natural gas that has been verified by a third party to have met specified environmental targets during production.<sup>2058</sup> He asserts that reducing methane intensity of the supply portfolio through the purchase of RSG for a modest premium benefits DTE's customers by reducing the direct methane emissions occurring at the point of production and thereby reducing the impact of those avoided emissions on climate change, which impacts all DTE's customers, and that purchasing RSG from suppliers will encourage other suppliers to develop similar certified RSG products, increasing the overall supply of RSG in the market.<sup>2059</sup> He adds that the procurement of RSG is an area where DTE can have reduce the methane intensity of the portfolio by quantifiable amounts.<sup>2060</sup>

Mr. Decker states that some industry peers have not contemplated a net zero strategy, some were in the infancy of contemplating the impact of more environmentally friendly emissions (i.e., reduced methane emissions, and RSG) and others had already procured contracts committing to RSG in their portfolios.<sup>2061</sup> He asserts that DTE Gas believes certification and verification is a necessity for procuring RSG, and acknowledges

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<sup>2057</sup> Id..

<sup>2058</sup> 2 Tr 67.

<sup>2059</sup> 2 Tr 70.

<sup>2060</sup> 2 Tr 69.

<sup>2061</sup> 2 Tr 71.

that currently there is not uniformity in the certification process.<sup>2062</sup> He adds that DTE has not committed to a specific certification process.<sup>2063</sup>

Mr. Decker states that in 2022, DTE issued a Request for Information (RFI) for RSG to understand the market dynamics and purchased 1,134,200 Dth of RSG, and in 2023, DTE issued a second RFI and purchased 1,990,200 Dth of RSG.<sup>2064</sup> He adds that the total cost for the 2022 RSG was \$7,858,562, which includes the commodity cost of \$7,821,754 and a premium of \$36,808 (Premium), while the 2023 RSG premium cost was \$29,853.<sup>2065</sup> He states that DTE is seeking recovery for both the commodity cost of \$7,821,754 and the premium of \$36,808 in the 2022-23 GCR Reconciliation Case No. U-21065, and will seek recovery of the \$29,853 for the RSG gas purchased in 2023 in the 2023-24 GCR reconciliation case.<sup>2066</sup> He adds that DTE would like the Commission to offer guidance on the integration of RSG into the portfolio as DTE continues to develop a robust RSG procurement strategy.<sup>2067</sup> He states that DTE is forecasting a purchase of 4,000,000 Dth of RSG gas with a premium price of \$0.045 per Dth based on current market conditions, which will result in a total expected premium expense of \$180,000, the amount DTE has included in its projected test year.<sup>2068</sup> He asserts that DTE estimates this would prevent approximately 4,000 to 8,000 metric tons CO<sub>2</sub>e from being released to the atmosphere, depending on the methane intensity of the RSG purchased.<sup>2069</sup>

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<sup>2062</sup> 2 Tr 71, 72.

<sup>2063</sup> 2 Tr 72.

<sup>2064</sup> 2 Tr 73; Ex. A-22, Sch. L2 and Sch. L3.

<sup>2065</sup> 2 Tr 77; Ex. A-22, Sch. L3.

<sup>2066</sup> 2 Tr 78.

<sup>2067</sup> 2 Tr 80.

<sup>2068</sup> 2 Tr 81; Ex. A-22, Sch. L3.

<sup>2069</sup> Id.

Ms. Royal states that it is Staff's recommendation that the RSG premium of \$180,000 should not be included in DTE's case.<sup>2070</sup> She adds that, based on how Staff interprets MCL 460.6h, premiums for RSG purchases cannot be included in the GCR filing until such time as the Commission has an approved a state or a federal mandate to reduce and/or mitigate carbon emissions before it can be considered as a reasonable and prudent GCR expense.<sup>2071</sup> She adds that until such time, the actual RSG purchases can be reviewed for reasonable and prudence in the annual GCR process.<sup>2072</sup>

Mr. Coppola states that in Case No. U-21064, the Commission warned the Company that the RSG premiums paid for gas purchases were not likely to be recovered in the Gas Cost Recovery reconciliation case, with the Commission suggesting that DTE try to make a case to recover the premiums paid in a general rate case.<sup>2073</sup> He adds that DTE anticipates purchasing 4,000,000 Dth of RSG at a premium of \$0.045 per Dth, which translates to a total premium amount of \$180,000.<sup>2074</sup>

Mr. Coppola states that DTE has put forth bits and pieces of information with little to no substance to allow an adequate assessment of whether the proposal to purchase RSG will make a significant contribution to DTE's total greenhouse gas reduction goals by 2050 or the larger benefit to society.<sup>2075</sup> Noting that although gas producers and transporters need to do the utmost to reduce emissions in the production and transportation of natural gas, he states that the natural gas industry and subgroups within the larger industry can establish standards that producers, transporters, and distributors

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<sup>2070</sup> 4 Tr 1813.

<sup>2071</sup> 4 Tr 1814.; Ex. S-11.5, S-11.6.

<sup>2072</sup> *Id.*

<sup>2073</sup> 4 Tr 1556.

<sup>2074</sup> 4 Tr 1558.

<sup>2075</sup> 4 Tr 1559.

should follow, and that if certification is necessary, that is a cost of doing business and should not require a separate premium to be paid by entities buying their product.<sup>2076</sup> He adds that there are initiatives at the federal level that could render DTE's RSG proposal unnecessary.<sup>2077</sup>

Mr. Coppola states that DTE forecasted 148,816,000 Dth of gas purchases for the 2023-2024 GCR year, and that if DTE were to pay an RSG premium of 4.5 cents per Dth on half of the purchases, the incremental annual cost would be in excess of \$3.3 million; if on 100% of the volumes, the incremental cost would be more than \$6.6 million annually.<sup>2078</sup>

Mr. Coppola states that DTE admitted that it is possible that both RSG and non-RSG may have the same methane intensity, and thus, asserts that there is no way for DTE to be sure that it would receive the low carbon intensity natural gas that it paid a premium to purchase and that it is likely it would not receive the same gas supply it purchased at a premium.<sup>2079</sup>

Mr. Coppola asserts that DTE's eagerness to purchase RSG seems highly influenced by its corporate goal of achieving net-zero carbon emissions by 2050 and burnishing its image as a socially responsible ESG company, such that the payment of premiums to purchase RSG is no different than advertising costs to enhance DTE's and its parent company's corporate image and that those costs should be paid by shareholders.<sup>2080</sup>

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<sup>2076</sup> 4 Tr 1560.

<sup>2077</sup> 4 Tr 1560-1561.

<sup>2078</sup> 4 Tr 1561.

<sup>2079</sup> 4 Tr 1562.

<sup>2080</sup> 4 Tr 1564.

Thus, Mr. Coppola recommends that the Commission reject DTE's proposal to include \$180,000 of RSG premium costs in this rate case based on a determination that DTE's RSG proposal is still incomplete and does not adequately identify a significantly beneficial impact to reduce greenhouse emissions or to customers.<sup>2081</sup> He adds that the Commission should also determine that DTE's RSG proposal is premature given the current state of this issue within the natural gas industry, the lack of industry standards for all participants to adhere to as part of routine business operations, and recent legislative and EPA initiatives on methane reductions in the gas production areas.<sup>2082</sup>

CEO asserts that DTE's proposal to purchase Responsibly Sourced Gas (RSG) will have limited impact because upstream emissions represent a far smaller share of DTE's total emissions than emissions associated with DTE's customers' consumption.<sup>2083</sup> Mr. Siddique states that DTE's RSG proposal would reduce DTE's total emissions 0.047% - 0.095% for its test year through the purchase of RSG, with a much greater proportion of emissions attributable to end-use, with about 90% of total GHG emissions take place at customer end use.<sup>2084</sup> He adds that DTE fails to demonstrate how the inclusion of RSG in its portfolio will have a cost-effective impact on its long-term emissions reduction goals.<sup>2085</sup>

Mr. Siddique states that before DTE purchased RSG, it should have prepared a plan to achieve its upstream, mid-stream, and downstream decarbonization goals, and should have determined the role of RSG in achieving those goals.<sup>2086</sup> He adds that DTE

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<sup>2081</sup> Id.

<sup>2082</sup> 4 Tr 1564-1565.

<sup>2083</sup> 4 Tr 780-781.

<sup>2084</sup> 4 Tr 781.

<sup>2085</sup> Id.

<sup>2086</sup> Id.

needs to develop an RSG purchase strategy based on a cost-benefit analysis.<sup>2087</sup> He asserts that since DTE pays a premium when it purchases RSG, the Commission should not approve recovery of DTE's RSG premium costs until DTE justifies that it did a proper cost-benefit analysis.<sup>2088</sup> He adds that DTE needs to focus on reducing emissions from customer end-use which is responsible for majority of the emissions.<sup>2089</sup>

Mr. Siddique states that DTE's projected CO<sub>2</sub>e emission reduction estimation through RSG is an extremely small proportion of total emissions (upstream, midstream, operations and end-use combustion emissions).<sup>2090</sup> He adds that emissions reduced from RSG purchased in the test year will be a minimal 0.047% - 0.095%, that the vast majority of DTE's emissions occur with end use combustion, and that DTE never justifies the premium it pays for RSG.<sup>2091</sup> He states that DTE needs a carbon reduction plan which analyzes the premium it pays for RSG as part of a long-term strategy to reduce all of its carbon emissions, and that the plan should include a cost benefit analysis that analyzes RSG as a cost-effective method for reducing upstream emissions.<sup>2092</sup>

Ms. Napoleon states that DTE has not committed to a specific certification standard or process, only stating that "at a minimum, third party verification is a criterion that will be used when procuring RSG."<sup>2093</sup> She asserts that DTE is relying on RSG as a decarbonization strategy without any indication that it reduces emissions.<sup>2094</sup> She states that there are many issues with relying on RSG as a long-term decarbonization strategy,

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<sup>2087</sup> Id.

<sup>2088</sup> Id.

<sup>2089</sup> Id.

<sup>2090</sup> 4 Tr 784.

<sup>2091</sup> 4 Tr 785.

<sup>2092</sup> Id.

<sup>2093</sup> 4 Tr 917

<sup>2094</sup> 4 Tr 918.

including a) that RSG is not regulated, and private standards for RSG lack uniformity, b) DTE has not set specific requirements for emissions reductions from RSG, c) federal emissions standards have likely reduced the benefits of RSG, d) the potential for emissions reductions from RSG is limited, e) DTE has not justified the cost-effectiveness of RSG compared to other GHG emissions reduction strategies, and f) significant dependence on RSG may prolong dependence on the gas system.<sup>2095</sup>

Ms. Napoleon asserts that RSG does not represent a valid GHG reduction measure and that given the speculative nature of the GHG reductions from RSG, if approved this pilot might incur costs with no associated benefits to DTE customers or to the state.<sup>2096</sup> Thus, she states that the Commission should reject the RSG pilot.<sup>2097</sup>

Regarding DTE's carbon emissions offset program, Ms. Napoleon states that many offsets on the market today do not actually lead to GHG emissions reductions, and that the purchase of an offset that is not associated with a real emission reduction will not achieve the buyer's objective, which is to decrease net GHG emissions.<sup>2098</sup> She adds that DTE does not appear to be providing physical RNG to all participants.<sup>2099</sup> She asserts that it is critical that the Commission investigate whether the Natural Gas Balance (NGB) program provides net benefits to any ratepayers, whether they participate or not.<sup>2100</sup> She states that DTE "has not done an evaluation of the costs to customers" for any of the

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<sup>2095</sup> 4 Tr 919.

<sup>2096</sup> 4 Tr 922.

<sup>2097</sup> *Id.*

<sup>2098</sup> 4 Tr 923-924. Citations omitted.

<sup>2099</sup> 4 Tr 924.

<sup>2100</sup> 4 Tr 925-926.

initiatives to reduce customer emissions, including the voluntary carbon offset program and RNG.<sup>2101</sup>

Ms. Napoleon states that Michigan utilities' decarbonization approach should be considered in a holistic setting in which stakeholders (including gas and electric utilities) consider the challenges and opportunities of different pathways for achieving climate policy goals while reducing the risk of stranded assets, i.e., in a future of heat proceeding.<sup>2102</sup> She adds that until then and until there has been a full assessment of the net benefits of the NGB, the Commission should not approve the NGB or any similar programs, in this docket or in any other docket, and that if DTE wishes to pursue the NGB program, it should be funded by shareholders exclusively.<sup>2103</sup>

FLO asserts that DTE's Responsibly Sourced Gas proposal has no verifiable benefits and ultimately leads to further fossil gas production and its associated harms.<sup>2104</sup> Mr. Koepfel asserts that DTE Gas has not committed to a specific certification process for RSG, while acknowledging that there is no uniform certification process for RSG.<sup>2105</sup> He adds that, as such, the purported benefits, in the form of lower methane intensity, of these RSG purchases are difficult if not impossible to verify.<sup>2106</sup> He states that DTE Gas presents no compelling evidence that this purchase will generate any meaningful climate benefits.<sup>2107</sup> He adds that DTE's lack of detailed information on their RSG purchases

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<sup>2101</sup> 4 Tr 927; Ex. MEC-25.

<sup>2102</sup> 4 Tr 929.

<sup>2103</sup> *Id.*

<sup>2104</sup> 4 Tr 1012.

<sup>2105</sup> 4 Tr 1013. Citations omitted.

<sup>2106</sup> *Id.*

<sup>2107</sup> *Id.*

makes it impossible to independently verify whether the gas they are sourcing meets the conditions for the MiQ grade.<sup>2108</sup>

Mr. Decker counters that DTE realizes that the recovery mechanism is undefined as this initiative is new in the industry.<sup>2109</sup> He asserts that if the Commission determines recovery in the Rate Case is the appropriate path, then it will be removed from the corresponding GCR proceeding.<sup>2110</sup> He adds that should the Commission choose to disallow cost recovery in this proceeding and the corresponding GCR case, DTE would be open to regulatory accounting authority to defer recovery of certain costs associated with the premium associated with the procurement of responsibly sourced gas (RSG) costs until legislation is developed or a recovery mechanism is defined (whichever comes first).<sup>2111</sup> He states that the RSG industry is still emerging and has not been completely defined.<sup>2112</sup> He adds that DTE has chosen a proactive approach to participate in the reduction of methane intensity using RSG as an initial pilot to begin DTE's path to net zero.<sup>2113</sup> He argues that a more robust and prescriptive approach will be defined as DTE gains insight on the industry, the regulatory construct and possible legislation.<sup>2114</sup>

This PFD agrees with Staff, the Attorney General, MNSC, CEO and FLO that that the RSG premium of \$180,000 should not be included in DTE's case. This PFD finds that DTE has not provided adequate support that the proposal to purchase RSG will make a significant contribution to DTE's total greenhouse gas reduction goals. This PFD agrees

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<sup>2108</sup> 4 Tr 1014; Ex. FLO-33.

<sup>2109</sup> 2 Tr 130.

<sup>2110</sup> *Id.*

<sup>2111</sup> 2 Tr 130-131.

<sup>2112</sup> 2 Tr 131-132.

<sup>2113</sup> 2 Tr 132.

<sup>2114</sup> *Id.*

that DTE's RSG proposal is premature given the current state of this issue within the natural gas industry, the lack of industry standards for all participants to adhere to as part of routine business operations, and recent legislative and EPA initiatives on methane reductions in the gas production areas. This PFD notes that the Commission has recently reminded DTE of the necessity to fully support the benefits of RSG procurement.

In the December 9 order, the Commission expressed its expectation that DTE Gas provide "a better correlation between the costs of [research and development] with the reduction of risk and benefits of sustained services for customers in order to support that some portion of these expenses be included in customer rates." Similarly, should the company seek to recover all or a portion of RSG premiums in its reconciliation case or in future filings, it will need to see fuller support for the expected benefits to its customers compared to the additional costs incurred from emergent third-party certifications such as those verifying RSG. However, the record evidence in this case does not provide sufficient information on how RSG will benefit DTE Gas's customers, including potential cost savings from supply chain emissions reductions achieved by monitoring and certifying responsibly sourced and lower methane intensity natural gas.<sup>2115</sup>

Thus, this PFD recommends that the Commission adopt the proposed disallowances of \$180,000.

### **Energy Assistance Programs**

Mr. Sparks states that DTE provides energy assistance programs to both low-income and non-low-income customers, and includes DTE's Affordable Payment Plan or Low Income Self Sufficiency Program (LSP), and Residential Income Assistance and Low Income Assistance (RIA and LIA) credits.<sup>2116</sup> He adds that for non-low income customers, DTE provides energy assistance through a 25% match of the LIHEAP Direct Support program administered by Michigan Department of Health and Human Services (MDHHS), as well as Energy Waste Reduction (EWR) services.<sup>2117</sup> He states that DTE has

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<sup>2115</sup> Case No. U-21064, Order, October 12, 2023, p. 17.

<sup>2116</sup> 4 Tr 2217.

<sup>2117</sup> Id.

implemented the Payment Stability Plan (PSP) pilot as approved in the U-20929 Order to further understand and meet the energy affordability needs of its customers.<sup>2118</sup>

Mr. Sparks states that DTE is actively engaged in implementing the recommendations put forth by the Energy Affordability and Accessibility Collaborative (EAAC) subcommittee, which aim to streamline the energy assistance application process and establish a standardized partnership with the State, mirroring the successful data-sharing approach employed with the Michigan Department of Health and Human Services (MDHHS) during the LIHEAP direct support initiative.<sup>2119</sup>

Mr. Sparks states that Low Income Self-Sufficiency Program (LSP) is a 2-year payment plan for vulnerable customers to make affordable monthly payments based on income and energy usage.<sup>2120</sup> He adds that the plan eliminates any future late payment charges, and past due energy charges are frozen while the customer receives a monthly arrears forgiveness credit.<sup>2121</sup>

In January 2022, DTE implemented the Payment Stability Plan (PSP) pilot which is DTE's percentage of income payment plan (PIPP).<sup>2122</sup> Mr. Sparks states that the PSP pilot is a percentage of income-based program directed at low-income customers at or below 200% FPL.<sup>2123</sup> He adds that customers who receive either gas or electric utility service from DTE Gas or DTE Electric have a flat bill payment equivalent to 6% of the household gross income, while customers who receive both gas and electric utility service

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<sup>2118</sup> Id.

<sup>2119</sup> 4 Tr 2219-2220.

<sup>2120</sup> 4 Tr 2220.

<sup>2121</sup> Id.

<sup>2122</sup> 4 Tr 2224.

<sup>2123</sup> Id.

from the companies have a flat bill payment equivalent to 10% of the house hold gross income.<sup>2124</sup>

DTE asserts that another key program addressing energy sustainability for our low-income customers is the Residential Income Assistance (RIA) and Low-Income Assistance (LIA) credits.<sup>2125</sup> Mr. Sparks states that the RIA Credit offers low-income gas customers a monthly credit on their bill equal to the monthly customer charge, currently \$13.50 per month.<sup>2126</sup> He adds that to be eligible, the total household income cannot exceed 150% FPL, and that customers who receive energy assistance in the form of a Home Heating Credit (HHC), State Emergency Relief (SER) or One time assistance are automatically enrolled to receive the RIA credit.<sup>2127</sup> He states that in 2022, the total monthly average of households enrolled and receiving the gas RIA credit stood at 71,159.<sup>2128</sup> He adds DTE is projecting an average of 70,000 customers per month totaling \$14.78M in the projected test year with a change from the current rate of \$13.50 to a proposed rate of \$17.60.<sup>2129</sup>

DTE states that the LIA credit offers qualifying low-income gas customers a monthly credit of \$30.00 on their bill, and that to be eligible for the LIA credit, like RIA, the total household income cannot exceed 150% FPL.<sup>2130</sup> Mr. Sparks states that DTE Gas is including LIA for 33,000 customers in rates in this case.<sup>2131</sup> He adds that in 2022 48,000 households enrolled in the program with a monthly average of approximately 38,000.<sup>2132</sup>

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<sup>2124</sup> Id.

<sup>2125</sup> 4 Tr 2225.

<sup>2126</sup> Id.

<sup>2127</sup> Id.

<sup>2128</sup> 4 Tr 2226-2227, Table 3.

<sup>2129</sup> 4 Tr 2227.

<sup>2130</sup> Id.

<sup>2131</sup> Id.

<sup>2132</sup> 4 Tr 2228, Table 4.

DTE is proposing to increase the amount of the credit from \$30.00 to \$40.00.<sup>2133</sup> Mr. Sparks states that when the LIA was originally proposed and approved the LIA covered approximately 68% of the customer's customer and distribution charges (not including GCR or GCC).<sup>2134</sup> He adds that based on final rates in U-20940, a \$30 per month LIA would cover 58% of a customer's customer and distribution charges, and that in the current case, for a customer using 10 Mcf per month, a 68% LIA credit calculated for this amount would be \$45 per month.<sup>2135</sup> He states that DTE Gas is proposing to increase the LIA to \$40 per month to provide low income customers receiving the LIA a credit that is as meaningful as when it was originally proposed.<sup>2136</sup> He adds that as rates change, DTE plans to maintain an LIA that will offset approximately 70% of a customer's distribution charges, assuming 10 Mcf usage.<sup>2137</sup>

Intervenors such as Staff and FLO take issue with the LIA and RIA credits.

Regarding energy assistance proposals, Ms. Braunschweig states that as directed in the DTE Electric rate case order in Case No. U-20836, the Commission charged the EAAC with reviewing a report detailing LIA enrollment and to discuss the LIA enrollment assignment and enrollment cap, followed by submitting a report and recommendations to the Commission.<sup>2138</sup> She asserts that in the December 21, 2023 Order in Case No. U-20757, the Commission reaffirmed its interest in the EAAC's analysis of utilities' RIA/LIA as fulfillment of MCL 5 460.11(2) and directed Staff to include analysis of PIPPs and Michigan Energy Assistance Program (MEAP) offerings to assist the Commission in

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<sup>2133</sup> 4 Tr 2230.

<sup>2134</sup> Id.

<sup>2135</sup> Id.

<sup>2136</sup> Id.

<sup>2137</sup> 4 Tr 2231.

<sup>2138</sup> 4 Tr 1761-1762. Citation omitted.

understanding current energy assistance offerings.<sup>2139</sup> She states that Michigan's most vulnerable customers would benefit from additional assistance but is not persuaded that DTE provides the comprehensive analysis and diverse, collaborative input the Commission is looking for to inform utility energy assistance changes.<sup>2140</sup> She adds that Staff's position is that collaborative discussions with interested/invested parties as well as all investor-owned utilities will lead to the most informed positions and decisions on this matter.<sup>2141</sup> She notes that the Affordability, Alignment, and Assistance subcommittee (AAA) of the EAAC has already outlined three options to replace or modify the current RIA and LIA credits, including cost estimates based on utilities that complied with the AAA data requests.<sup>2142</sup> Noting that the AAA report has not yet been submitted, she states that Staff's preliminary admission of EAAC materials in the instant case aims only to demonstrate to the Commission that proposals similar to DTE's proposal are being examined in the EAAC, and that Staff's aim is not to propose any of the EAAC's RIA/LIA reforms for approval in the instant case, as they have not yet been fully examined.<sup>2143</sup>

As stated, Staff recommends that DTE Gas's proposal to increase the LIA credit from \$30 to \$40 should be rejected, taking the position that the LIA credit should remain at \$30 while the Commission's EAAC is ongoing. DTE counters that it has identified and proposed a change that can be implemented in 2024, before the completion of the EAAC, without incurring costly expenditures.<sup>2144</sup> DTE asserts that it is not proposing changes to the structure of the eligibility requirements or recovery mechanisms, and given that the

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<sup>2139</sup> 4 Tr 1762.

<sup>2140</sup> *Id.*

<sup>2141</sup> *Id.*

<sup>2142</sup> 4 Tr 1763.

<sup>2143</sup> 4 Tr 1763-1764.

<sup>2144</sup> DTE initial brief, p. 154.

LIA has proven effective, this change should be deemed prudent.<sup>2145</sup> DTE argues that Staff's recommended rejection is shortsighted, as implementing a concrete proposal with a definite implementation date would directly benefit customers when this rate case is complete.<sup>2146</sup> DTE states that Staff's recommendation would deny a positive change merely because a better one might emerge in the future, which DTE asserts would not serve the best interests of customers who urgently require bill relief now.<sup>2147</sup>

Ms. Watts, a DTE customer, states that she does not understand why customers eligible for both cannot receive both the RIA and LIA credits at the same time, offering that in her opinion, they should.<sup>2148</sup> In rebuttal, Ms. Braunschweig states that the LIA was designed to be a distinct program from the RIA and Staff recommends that be maintained until the Commission's EAAC Affordability, Alignment, and Assistance subcommittee (AAA) analyzes all current utility-based energy assistance offerings that fulfill MCL 460.11(2) and provides a recommendation for potential changes.<sup>2149</sup>

FLO recommends that the Commission expand the amount, enrollment, and transparency of the LIA credit, that the Commission clarify that the purpose of the RIA credit is to cover 100% of each bill's monthly customer charge, and that LIA participation should not disqualify customers from receiving the RIA credit.<sup>2150</sup> Mr. Cira-Reyes adds that the Commission should require DTE Gas to increase the amount of the credit to an amount equivalent to at least 70% of a typical customer's monthly bill now, the Commission should approve funding for expanded enrollment so that the program will

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<sup>2145</sup> Id., p. 154-155.

<sup>2146</sup> Id., p. 155.

<sup>2147</sup> Id.

<sup>2148</sup> 4 Tr 1248.

<sup>2149</sup> 4 Tr 1767-1768.

<sup>2150</sup> 4 Tr 1170.

match the number of eligible customers, and that the Commission should direct DTE to advertise adequately and conduct meaningful outreach on the LIA credit.<sup>2151</sup>

Mr. Cira-Reyes states that because the LIA credit has remained the same fixed dollar amount (\$30) since its inception, it has waned in value over the last seven years.<sup>2152</sup> He adds that while DTE considered raising the credit to cover the equivalent of 68% of a customer's bill — the original value of the LIA credit — DTE has chosen to propose an increase in the instant case that would cover only 60% of the bill.<sup>2153</sup>

Mr. Cira-Reyes asserts that DTE Gas's proposal to account for only 33,000 customers in its current request is nonsensical given that LIA enrollment has trended closer to 38,000 customers over time.<sup>2154</sup> He adds that in the past, the Commission has stated that it finds the LIA program "valuable" and that it "encourages the [C]ompany to continue the enrollment of interested customers."<sup>2155</sup> He states that to encourage such enrollment, in 2020, the Commission authorized DTE Gas to track enrollments up to 50,000 for LIA "to be booked as a regulatory asset."<sup>2156</sup> He notes that DTE Gas has refused to enroll more than 40,000 customers in the LIA credit since 2020.<sup>2157</sup>

Mr. Cira-Reyes states that a look at DTE Gas's 2023–2024 "Payment Assistance Programs" brochure, as well as at brochures from the last few years, reveals that the LIA credit is not listed as a possible assistance option, and similarly, that DTE Gas's "Payment Assistance Programs" webpage does not list the LIA.<sup>2158</sup> He adds that DTE explains that

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<sup>2151</sup> 4 Tr 1170.

<sup>2152</sup> 4 Tr 1171.

<sup>2153</sup> 4 Tr 1171-1172.

<sup>2154</sup> 4 Tr 1173.

<sup>2155</sup> *Id.*, quoting Case No. U-20561, Order, May 8, 2020, p. 180.

<sup>2156</sup> *Id.*, quoting p. 181.

<sup>2157</sup> 4 Tr 1174, Table 1.

<sup>2158</sup> 4 Tr 1174; Ex. FLO-227, Ex. FLO-228.

it chose not to include the credit on either the brochure or website because of the credit's enrollment cap, which he asserts is a poor reason not to advertise the LIA, and that keeping this program secret from customers prevents otherwise LIA-eligible customers from even inquiring about the credit due to lack of knowledge.<sup>2159</sup>

DTE counters that the simultaneous participation in LIA and RIA runs counter to the initial intent of LIA, which was originally approved by the Commission as an alternative to the RIA with limited enrollment.<sup>2160</sup> Mr. Sparks adds that if DTE were to enroll all eligible low-income customers in the LIA, that would result in more than doubling the combined cost of DTE's low-income programs.<sup>2161</sup>

In reply to Mr. Cira-Reyes statement that "DTE Gas must replace its various, disjointed assistance programs with one unified, central program that ensures customers are not paying more for their energy bills than they can afford," Ms. Braunschweig counters that this is what the EAAC's Affordability, Alignment, and Assistance subcommittee is currently working on, and Staff recommends the Commission allow this analysis and restructuring recommendations to come from the AAA and hold off on utility energy assistance changes until that point.<sup>2162</sup>

Regarding Mr. Cira-Reyes' alternative proposal that "the MPSC should expand the amount, enrollment, and transparency of the LIA credit," Ms. Braunschweig counters Staff does not support changes to this program, as the AAA is currently working on analyzing all current utility-based energy assistance, and approving programmatic changes to the LIA in the short-term could incur operations and management costs that

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<sup>2159</sup> 4 Tr 1174-1175; Ex. FLO-229.

<sup>2160</sup> DTE initial brief, p. 155.

<sup>2161</sup> 4 Tr 2239.

<sup>2162</sup> 4 Tr 1769.

would be an imprudent use of spending when the program could no longer look the same in a year -- thus causing duplicative costs and efforts.<sup>2163</sup> She adds that, regarding Mr. Cira-Reyes specifically addressing an “enrollment issue” with the LIA, in which DTE has not enrolled more than 40,000 customers in the LIA since 2020, this is not an enrollment issue, rather enrollment being capped at 33,000 average monthly customers is a defining requirement of the LIA credit.<sup>2164</sup>

Regarding Mr. Cira-Reyes additionally expressing that the RIA becomes less valuable with an Infrastructure-Recovery Mechanism (IRM) in place and the RIA should be increased to cover the IRM, Ms. Braunschweig counters that the IRM is specifically designed to recover “infrastructure capital expenditures made in DTE’s Gas Renewal Program (GRP), Meter Assembly Check / Meter Move-out Program (MAC MMO) and Pipeline Integrity Program (PI) for each year in the five-year period of 2022-2026” and receives an annual reconciliation with a resulting change to the amount of the IRM, if necessary, which allows for the IRM to be adjusted outside of rate cases, subject to Staff audits.<sup>2165</sup> She adds that the IRM is a special case in which costs can be approved outside of the contested proceeding and levied through a surcharge, and unlike the IRM, the RIA does not have a special proceeding to be adjusted outside of rate cases, was not designed to discriminately chose which costs customers would pay for and which it would not, outside of the monthly service charge, and that the credit changing amounts with each IRM reconciliation could lead to additional burdens of adjusting the credit and communicating with customers explaining the change in the credit.<sup>2166</sup>

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<sup>2163</sup> 4 Tr 1769-1770.

<sup>2164</sup> 4 Tr 1770. Citation omitted.

<sup>2165</sup> 4 Tr 1771.

<sup>2166</sup> Id.

Regarding Mr. Cira-Reyes' recommendation for a proposed timeline on Payment Stability Plan (PSP/PIPP) results, Ms. Braunschweig counters that Staff does not support prematurely approving a full-scale PIPP/PSP until a comprehensive analysis has been performed, which is likely to occur by the end of this calendar year with an expected Staff report in the first quarter of 2025.<sup>2167</sup> She adds that the Commission has expressed agreement with this notion in stating "The Commission further agrees with the Staff that it is not appropriate to prematurely approve permanent PIPP programs."<sup>2168</sup>

Mr. Cira-Reyes argues that the BudgetWise settlement bills are too high for customers to manage.<sup>2169</sup> DTE counters that this program adjusts monthly bills only if usage currently exceeds 10% of the twelve-month year's average consumption.<sup>2170</sup> Similarly, Ms. Braunschweig counters that determining how much a household is able to pay under this particular tariff is effectively unknowable, that there are issues with the ambiguity of what "ability to pay" means, and that this tariff is not considered a low-income energy assistance program under MCL 460.11(2), rendering the proposal inappropriate.<sup>2171</sup>

FLO's Mr. Schott states that the RIA lacks accessible design and enrollment processes needed to be a reliable affordability solution for DTE Gas's low-income customer base.<sup>2172</sup> Ms. Braunschweig counters, urging that the AAA be allowed to address these issues and explore reforming utility energy assistance alongside analysis of the PIPPs so that these programs are not analyzed individually, rather

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<sup>2167</sup> 4 Tr 1772.

<sup>2168</sup> Id., citing Case No. U-20757, Order, December 21, 2023, p. 5.

<sup>2169</sup> 4 Tr 1186.

<sup>2170</sup> DTE initial brief, p. 155.

<sup>2171</sup> 4 Tr 1772-1773.

<sup>2172</sup> 4 Tr 1071.

comprehensively, since many energy assistance programs are interconnected.<sup>2173</sup> She adds that, regarding Mr. Schott's claim that the Home Heating Credit (HHC) is the only program that automatically enrolls a customer in the RIA credit, Staff sees no evidence that that claim is supported, and that the main identifiers for RIA eligibility and thus automatic enrollment into this program are: the Michigan Department of Health and Human Services (MDHHS), the Michigan Department of Treasury, or Michigan Energy Assistance Program (MEAP) grantees notifying utilities of a customer receiving a State Emergency Relief (SER) payment, a Home Heating Credit (HHC) energy draft, or one-time assistance payment, respectively, that would get applied to their account.<sup>2174</sup> She adds that these programs require the utilities to apply a payment to the customer's account on the program manager's behalf, which identify the customer as RIA-qualified, as per MCL 460.11(2) and defined in MCL 460.10(t).<sup>2175</sup>

Ms. Braunschweig states that Mr. Schott's statement that "DTE also proposes to reduce the number of customers enrolled from a monthly average of 38,000 in 2022 to 33,000, further diminishing the credit's effectiveness" is unsupported, noting that in Case No. U-20940, December 9, 2021 order, Attachment B, p. 7 shows the credit is available to up to 33,000 qualifying customers in the approved tariff sheets and in Case No. U-20642 August 20, 2020 order, Attachment B, on the approved tariff sheet D-13.00, it shows the credit is available to up to 33,000 qualifying customers.<sup>2176</sup> She adds that

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<sup>2173</sup> 4 Tr 1773-1774. Citations omitted.

<sup>2174</sup> 4 Tr 1774-1775.

<sup>2175</sup> 4 Tr 1775.

<sup>2176</sup> 4 Tr 1776.

based on the provided evidence, DTE has been approved to target an enrollment of 33,000 monthly LIA credit disbursements.<sup>2177</sup>

Regarding Mr. Schott's recommendation to require a maximum energy burden of 6% of income for all customers and for DTE, Staff, the EAAC and interested parties to propose a pathway to achieve this goal, Ms. Braunschweig counters that the EAAC and Staff have discussed the hurdles of proposals similar to this to the extent of identifying customers and determined that it is an invasion of privacy and increases security risks to have an investor-owned utility collect and store income information on all its customers.<sup>2178</sup> She adds that Staff supports customers reaching out and receiving assistance if eligible but does not currently support requiring income reporting of all customers.<sup>2179</sup>

Regarding Mr. Schott's recommendation to require DTE to "size its existing affordability and assistance programs to align with the number of customers who are eligible," Ms. Braunschweig states that the RIA is designed to serve all identified eligible customers and recover the costs associated with this program through rates by including a projected enrollment number; that all who are eligible and apply/are identified are entitled to the credit, however, overestimating customer counts allows DTE to retain the excess unused dollars recovered by ratepayers, absent deferred accounting for differences between actuals above or below the projection used to set rates; and that even with deferred accounting, it is appropriate to utilize the most accurate and reliable forecast to set rates.<sup>2180</sup>

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<sup>2177</sup> *Id.*

<sup>2178</sup> 4 Tr 1777.

<sup>2179</sup> *Id.*

<sup>2180</sup> 4 Tr 1778. Citation omitted.

Regarding Mr. Schott's recommendation to enroll entire census tracts in energy assistance programs, Ms. Braunschweig counters that Staff does not support this proposal, as every household's income could be ensured to fall within the income requirements as set forth in statute is lacking on the record.<sup>2181</sup>

Regarding Mr. Schott's recommendation to have the Commission (and by extension the Commission's Low Income Energy Policy Board/EAAC) research affordability structures, Ms. Braunschweig states that the legislatively required 10-month date for a Commission decision in the instant case is approximately Friday Nov. 8, 2024, and adding Mr. Schott's recommended 90-120 days would place the end of the recommended affordability analysis on approximately February 8, or March 8, 2025, which would be no sooner than the current AAA plan to have PIPP analysis integrated with a plan to analyze/reform the current utility energy assistance offerings by the end of this year and a report to the Commission filed in the first quarter of 2025.<sup>2182</sup> She adds that Staff's analysis plan is more comprehensive Mr. Schott's plan to have the same workgroup "research affordability structures."<sup>2183</sup>

In rebuttal, FLO disagrees with Staff's proposal that the Commission "reject the Company's LIA credit increase proposal to allow this issue to continue to be more fully analyzed and addressed in the Commission's EAAC workgroup."<sup>2184</sup> Mr. Koepfel counters that he disagrees with the assumption that the processes underway through the EAAC will yield comprehensive reforms that meet household needs.<sup>2185</sup> He adds that

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<sup>2181</sup> Id.

<sup>2182</sup> 4 Tr 1779.

<sup>2183</sup> Id.

<sup>2184</sup> 4 Tr 1044.

<sup>2185</sup> 4 Tr 1045.

Staff fails to consider the material urgency of these issues for impacted households, as gas bills are not affordable for LMI customers, and the present assistance problems are woefully inadequate.<sup>2186</sup> He asserts that continuing to delay increases to assistance out of regard for a procedurally unjust process that is unlikely to yield cohesive affordability reform, all while real customers suffer under unaffordable bills, is neither reasonable nor prudent.<sup>2187</sup> Thus, he recommends the Commission approve an increase in the LIA credit for DTE Gas customers to cover 70% of the typical monthly bill, and that the Commission order DTE Gas to coordinate with all 15 other electric utilities which serve their customers (including DTE Electric, Consumers Energy Company, Upper Peninsula Power Company, and others) and propose a plan for transitioning all assistance or affordability crediting available to cover part or all of a customer's gas bill to their electric bill in the instance that a household receiving assistance chooses to electrify.<sup>2188</sup>

This PFD agrees with DTE that the LIA credit should be increased from \$30 to \$40, which change can be implemented in 2024 without incurring costly expenditures. As DTE asserts, the LIA has proven effective, the increase is in the best interests of customers who urgently require bill relief, and this increase does not involve a change to the structure of the eligibility requirements or recovery mechanisms.

This PFD finds that many of the other stated criticisms and asserted shortcomings of DTE's energy assistance programs are well-taken and should be further evaluated for the Commission's consideration. Indeed, this PFD notes that Staff agrees that Michigan's most vulnerable customers would benefit from additional assistance and is not persuaded

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<sup>2186</sup> 4 Tr 1046.

<sup>2187</sup> Id.

<sup>2188</sup> Id.

that DTE provides the comprehensive analysis and diverse, collaborative input the Commission is looking for to inform utility energy assistance changes. This PFD also notes that the record supports that DTE may not be advertising adequately and conduct meaningful outreach on its energy assistance programs. However, this PFD does not find it appropriate to address these issues on this record in this rate case. This PFD agrees with Staff that collaborative discussions with interested/invested parties in the EAAC workgroups as well as all investor-owned utilities will lead to the most informed positions and decisions on this matter and that any final assessments and changes by the Commission should await the completion of the work by the EAAC.

Thus, this PFD recommends that the Commission adopt DTE's proposal to increase the LIA credit from \$30 to \$40.

### **Methane Leak Detection and Vegetation Management**

Ann Arbor states its concern that valuable street trees are dying as a result of gas leaks on DTE's system in the City.<sup>2189</sup> Dr. Stults states that based the Methane Detection Report prepared by Mr. Ackley, of the 50 active leak locations that were subject to pinpoint testing, Mr. Ackley identified 31 trees at 22 different locations as being actively damaged as a result of gas leaks.<sup>2190</sup> She adds that given that almost half of the leak sites examined had tree damage, it is likely that there are more trees being affected throughout the City in the identified areas.<sup>2191</sup> Dr. Stults asserts that DTE is violating state law by operating its pipeline system in a way that damages the City's trees in the right of way, asserting that pursuant to Michigan law, public utility companies may not maintain pipelines in a

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<sup>2189</sup> 3 Tr 526.

<sup>2190</sup> Id.; Ex. AA-3.

<sup>2191</sup> Id.

way that destroys or injures any tree or shrub planted within any highway right of way or along the margin thereof, or purposely left there for shade or ornament.<sup>2192</sup>

Dr. Stults recommends that DTE focus on repairing leaks that are causing vegetation damage in Ann Arbor, rather than the more time-consuming and expensive process of replacing entire pipelines under its capital programs – especially considering Ann Arbor’s stated climate goals, the achievement of which would mean the City will no longer be using fossil gas by 2050.<sup>2193</sup> She adds that with that knowledge, it is not reasonable or prudent for DTE to invest in new capital that is intended to last far beyond the date it will be used and useful.<sup>2194</sup> She states that DTE should be required to pay the City for the value of its lost trees – or to replace damaged trees upon repair of the gas leak.<sup>2195</sup> She asserts that when it knew or should have known that a gas leak was damaging a tree, and did not repair that leak within six months of learning of the tree, that cost should be borne by shareholders because such costs are not reasonable and prudent.<sup>2196</sup> She adds that the Commission should require DTE to track all expenses related to tree death and soil remediation so it is possible to exclude those imprudently and unreasonably incurred costs.<sup>2197</sup>

DTE counters that that it has never been found to be in violation of MCL 247.185.<sup>2198</sup> DTE argues that Dr. Stults assumes without any actual evidence that methane is the cause or sole source of damage to any dying trees or vegetation in Ann

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<sup>2192</sup> 3 Tr 527, citing MCL 247.185.

<sup>2193</sup> 3 Tr 529.

<sup>2194</sup> *Id.*

<sup>2195</sup> *Id.*

<sup>2196</sup> *Id.*

<sup>2197</sup> 3 Tr 530.

<sup>2198</sup> DTE initial brief, p. 157.

Arbor. Mr. Kehoe states that DTE repairs thousands of leaks each year and it would be cost prohibitive for DTE Gas to contract an arborist to evaluate potential methane damage to trees or vegetation for each leak across DTE's service territory.<sup>2199</sup> He adds that DTE takes measures to protect trees to avoid damage when performing maintenance or construction activities, and that DTE remediates damage to trees or vegetation from maintenance or construction activities.<sup>2200</sup>

Ann Arbor also asserts that the Commission should disallow costs related to the Natural Gas Balance Program until DTE brings its operation and maintenance gas leak repair program into conformance with the law.<sup>2201</sup> In reply, DTE asserts that the assertion that DTE's LDAR program does not conform to applicable law is simply untrue.<sup>2202</sup> Mr. Decker adds that DTE is not seeking any costs in this case for its Natural Gas Balance Program.<sup>2203</sup>

This PFD agrees with DTE that Ann Arbor has not supported its assertion that DTE gas leaks are the cause of the trees asserted to be dying. Moreover, while Ann Arbor is free to pursue any cause of action it feels it may have for damages caused by gas leaks, this PFD concludes that a rate case is not an appropriate case to do so. This PFD finds that DTE has supported its assertion that it takes measures to protect trees to avoid damage when performing maintenance or construction activities and that it remediates damage to trees or vegetation from maintenance or construction activities. This PFD also agrees with DTE that it is cost prohibitive and thus unreasonable to require DTE to track

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<sup>2199</sup> 4 Tr 2053.

<sup>2200</sup> 4 Id.

<sup>2201</sup> 3 Tr 509.

<sup>2202</sup> DTE initial brief, p. 157.

<sup>2203</sup> 2 Tr 146.

all expenses related to tree death and soil remediation. Thus, this PFD recommends that the Commission reject Ann Arbor's claim and proposals.

### **Environmental Justice and Energy Transition**

MNSC recommends that DTE to develop a policy-consistent load forecast and evaluate the need for and prudence of its investments in light of that forecast.<sup>2204</sup> Dr. Hopkins states that “energy transition” means the transition away from fossil fuel energy sources and toward renewable and zero-carbon energy sources as part of an economy-wide transition to reduce greenhouse gas (GHG) emissions by 80 percent or more by 2050.<sup>2205</sup> He asserts that the primary pathways for energy transition in the building and industrial sectors are electricity decarbonization – which is aided by falling costs of renewable generation technologies such as solar and wind, and advances and falling costs in battery and other energy storage technology – and decarbonization of heating – which requires either substitution of fossil fuels with limited and/or expensive supplies of lower-carbon combustion fuels, or electrification (such as with highly efficient heat pump technologies).<sup>2206</sup>

Dr. Hopkins states that the energy transition will require substantial reductions in the amount of gas delivered.<sup>2207</sup> He adds that the Net Zero America study identified that pipeline gas use in Michigan would fall by a factor of two or more by 2050 in all scenarios that achieve net-zero emissions, and that in high electrification cases Michigan pipeline gas use falls by more than a factor of seven.<sup>2208</sup> He asserts that such reductions will

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<sup>2204</sup> 4 Tr 830.

<sup>2205</sup> 4 Tr 831.

<sup>2206</sup> 4 Tr 832.

<sup>2207</sup> 4 Tr 834.

<sup>2208</sup> 4 Tr 834-835; Ex. MEC-5.

require changes in DTE's rates and will change the competitive position of DTE's service compared with alternatives.<sup>2209</sup> He adds that some of DTE's assets may no longer be needed to provide service (that is, no longer used and useful) and would therefore need to be removed from the rate base.<sup>2210</sup> He asserts that if these assets are not fully depreciated, this could create stranded costs borne by either utility investors or the DTE's remaining customers.<sup>2211</sup>

Dr. Hopkins states that the federal government's Long-Term Strategy identifies that the primary goals for the next decade are to increase efficiency measures and sales of electric appliances, while in the longer term, the federal government has stated that all buildings need to be decarbonized through end-use electrification and significant implementation of energy efficiency measures to lower overall demand and reduce energy waste.<sup>2212</sup> He adds that in the industrial sector, low- and medium-temperature heat processes are priority candidates for industrial electrification in the near term through increased use of industrial heat pumps, electric boilers, or electromagnetic heating processes.<sup>2213</sup> As such, he asserts that energy demand overall is expected to decrease as efficiency improves, and the share of electricity in final energy demand will grow from about 50% in 2020 to 90% or more by 2050 because the onsite combustion of gas, oil, and other fuels will decrease substantially.<sup>2214</sup>

Dr. Hopkins states that given long lives of utility assets, practices relating to those assets will need to change during their lifetime, such that gas infrastructure investment

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<sup>2209</sup> 4 Tr 834.

<sup>2210</sup> *Id.*

<sup>2211</sup> *Id.*

<sup>2212</sup> 4 Tr 839-840. Citation omitted.

<sup>2213</sup> 4 Tr 840.

<sup>2214</sup> *Id.* Citation omitted.

practices that assume continuity with the past are no longer reasonable or justified.<sup>2215</sup> He asserts that DTE has not adjusted its load forecast and customer count forecast methodology or its analysis of customer attachments and community expansion to account for the energy transition.<sup>2216</sup> He asserts that the failure to do so is unreasonable and imprudent, and DTE should bear the costs and risks of its decisions in this regard.<sup>2217</sup>

Mr. Cebulko states that society is undergoing a fundamental energy transition in which society is shifting away from fossil fuels and towards renewable forms of energy, with the shift is primarily being driven by changing policy and changing economics.<sup>2218</sup> He states that the cost to transition to less carbon-intensive energy has plummeted in recent decades, most notably in the power generation sector.<sup>2219</sup>

Mr. Cebulko states that DTE's rate case does not reflect the changing landscape much less propose actions that will direct DTE down a path towards meeting the state's emissions reduction goals, and asserts that DTE does not have a plan to achieve the state's emissions reduction goals.<sup>2220</sup> He adds that DTE continues to invest in its delivery system as if it does not need to meet the state's emissions reduction targets or with due consideration for the coming energy transition, which he asserts is costly and risky for customers.<sup>2221</sup>

Mr. Cebulko states that to respond to the changing environment, DTE must take a different approach and look for opportunities to reduce its capital investment spending.<sup>2222</sup>

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<sup>2215</sup> 4 Tr 845.

<sup>2216</sup> Id.

<sup>2217</sup> Id.

<sup>2218</sup> 4 Tr 716.

<sup>2219</sup> 4 Tr 717.

<sup>2220</sup> Id.

<sup>2221</sup> Id.

<sup>2222</sup> Id.

He asserts that DTE must show the Commission how its spending, particularly its capital expenditures, are reasonable considering the state's emissions reduction goals and the larger energy transition.<sup>2223</sup>

Mr. Cebulko states his concern with DTE's pace and scope of its capital investment plan: a) DTE's own projections forecast declining customer demand, b) by not considering the impact of building electrification on its future demand, customer rates will increase more rapidly than anticipated, and c) DTE does not have a plan for meeting the state's emissions reduction targets.<sup>2224</sup> He adds that DTE states that it does not include the impacts of building electrification on its demand forecast as there is too much uncertainty related to the adoption of electrification technologies to accurately forecast, and that DTE has not conducted a study or analysis of the impacts of building electrification in its service territory.<sup>2225</sup>

Mr. Cebulko asserts that DTE should commit itself to reduce end-use combustion emissions to net-zero by 2050, which is aligned with the state's emissions reduction goals.<sup>2226</sup> He adds that DTE has indicated that it has not identified pathways to achieve the DTE Gas emission reduction goals and that DTE's plans remain indeterminate due to the uncertainty, cost, and feasibility of technology deployment.<sup>2227</sup> He asserts that DTE's Gas Delivery Plan is an ideal place for it to consider potential pathways and future energy scenarios.<sup>2228</sup>

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<sup>2223</sup> Id.

<sup>2224</sup> 4 Tr 719.

<sup>2225</sup> 4 Tr 729.

<sup>2226</sup> Id.

<sup>2227</sup> Id.

<sup>2228</sup> 4 Tr 734.

Mr. Cebulko recommend the Commission order DTE to use its Gas Delivery Plan to model specific emissions reductions pathways for meeting the state’s decarbonization goals, and report the potential costs, benefits, and risks of the various resources and investments used in each pathway.<sup>2229</sup> Further, he recommends the Commission order DTE to develop an interim plan by July 2025 that examines the decarbonization pathways or with its next general rate case, whichever comes first.<sup>2230</sup>

Mr. Cebulko states that DTE should be examining alternatives when making capital investments, particularly for pipeline replacements and capacity expansions, with the two most common types of alternatives being pipeline repairs and non-pipeline alternatives (NPA).<sup>2231</sup> He asserts that a 2023 study conducted by Gas Safety USA found that pipeline repair can cost between one tenth and one hundredth of the cost of pipeline replacement.<sup>2232</sup> He recommends that the Commission require DTE to work with stakeholders and Commission Staff to develop an NPA framework for analyzing capital investment projects going forward.<sup>2233</sup> He also recommends that the Commission require DTE to work with stakeholders and Staff to develop a framework for considering when pipeline repair is a suitable alternative to pipeline replacement projects.<sup>2234</sup> Noting that DTE does not use MiEJScreen or a similar mapping tool, he recommends that the Commission order DTE to immediately start using the tool to plan, develop, and implement its programs and capital investment decisions.<sup>2235</sup>

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<sup>2229</sup> 4 Tr 736.

<sup>2230</sup> Id.

<sup>2231</sup> Id.

<sup>2232</sup> 4 Tr 737. Citation omitted.

<sup>2233</sup> 4 Tr 738-739.

<sup>2234</sup> 4 Tr 739.

<sup>2235</sup> 4 Tr 756.

FLO states that DTE Gas proposes a plan to maximize profitable capital investment in the gas system without regard for the long-term, systemic impacts of doing so on its customer base, and especially on low-to-moderate income (LMI) and Black, Indigenous, and People Of Color (BIPOC) communities.<sup>2236</sup> Mr. Koepfel states that applying the social interest principle - the maximization of collective social benefit by assessing the full life cycle costs and benefits of energy decisions and distributing those costs and benefits equitably - would require DTE to conduct a rigorous analysis of the future of the gas system, minimize capital investment in soon-to-be-replaced infrastructure, and articulate and follow a clear plan for the equitable transition of LMI and BIPOC communities to a modern, high-functioning, and electrified energy system.<sup>2237</sup>

Mr. Koepfel states that significant change is taking place in the energy industry – commonly referred to as the energy transition -- driven largely by technological advancements, efforts to mitigate the effects of climate change, and efforts to address environmental quality and health.<sup>2238</sup> He asserts that presently, the distribution of burdens and benefits in the existing energy system is not equitable; LMI and BIPOC communities bear the greatest costs and receive the lowest benefits from the system.<sup>2239</sup> He asserts that it is just and reasonable for the Commission to focus on improving affordability in a general rate case by assessing the cost of energy, which is within the Commission’s purview.<sup>2240</sup>

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<sup>2236</sup> 4 Tr 984.

<sup>2237</sup> 4 Tr 984-985.

<sup>2238</sup> 4 Tr 985-986.

<sup>2239</sup> 4 Tr 986.

<sup>2240</sup> 4 Tr 987, quoting the Commission’s definition of energy affordability in Case No. U-20757, Order, December 21, 2023, p. 36 (“The extent to which a household has the resources to meet their home energy needs for heating, cooling and other uses in a healthy, sustainable and energy efficient manner without compromising a household’s ability to meet other basic needs.”).

Mr. Koepfel states that the gas distribution system and the electric distribution are legacy fossil fuel systems which currently serve ratepayers.<sup>2241</sup> He asserts that both systems are at operational odds with the emerging clean and renewable system, in which distributed generation and storage of electricity is a significant resource, and electricity meets the majority of energy needs.<sup>2242</sup> He states that narrow and short-term cost-benefit analyses continue to lead DTE Electric and DTE Gas towards investing to keep both systems functional, which extends the mid-transition period - the period during which energy supply is constrained by a goal of reducing or eliminating greenhouse gas emissions and comprised of fossil carbon emitting systems and zero-carbon systems that both exist at sufficient scale to impose operationally relevant constraints on the other - instead of investing in the most efficient transition possible.<sup>2243</sup>

Mr. Koepfel states that the continued extraction, transportation, and end-use of gas have significant equity impacts.<sup>2244</sup> He argues that the Commission, DTE Energy, DTE Electric, and DTE Gas should utilize longer-term cost-benefit analysis that integrates electric and gas planning to ensure that investments made in the gas system are truly efficient, and should focus on home repair, weatherization, and electrification of homes instead of on continued investment in the gas distribution system.<sup>2245</sup>

Mr. Koepfel states that the Gas Distribution Plan and Gas Renewal Plan prolong the mid-transition by promoting expansion of the gas system.<sup>2246</sup> He adds that DTE Gas has no specific date at which it plans to cease operations and has initiated no engineering

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<sup>2241</sup> 4 Tr 995.

<sup>2242</sup> 4 Tr 995-996.

<sup>2243</sup> 4 Tr 988, 996.

<sup>2244</sup> 4 Tr 996.

<sup>2245</sup> 4 Tr 997-998.

<sup>2246</sup> 4 Tr 1008.

analysis of how phased retirement would work, and that DTE Gas projects increasing customer counts through 2028, which he asserts appear incongruent with decommissioning and increased electrification.<sup>2247</sup> He asserts that DTE Gas appears to ignore the prevalence of electrification as a central focus of decarbonization, stating that it is “premature to speculate” on whether electrification will impact their demand over the next thirty years.<sup>2248</sup>

Mr. Koepfel states that by making long-term investments in rebuilding two decrepit systems in parallel instead of focusing on investing in a single, modernized electric system that can meet the energy needs of these communities, the inevitable consequence of creating this profit-maximizing parallel system reliance is stranded assets for which DTE will certainly try to hold ratepayers liable.<sup>2249</sup>

Mr. Koepfel asserts that DTE Gas fails to analyze housing quality as a core component of gas distribution system planning.<sup>2250</sup> He states that Energy-efficient housing is critical to addressing the affordability crisis, as energy-inefficient homes result in higher energy bills for the LMI ratepayers who overwhelmingly live in them and receive proportionately less support from utility energy efficiency programming.<sup>2251</sup>

Mr. Koepfel states that the Commission should order integrated gas and electric distribution and resource planning to shorten the mid-transition period and accelerate an equitable clean energy transition.<sup>2252</sup> In addition, he asserts that the Commission should order DTE Gas to conduct integrated infrastructure and equity analysis with DTE Electric

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<sup>2247</sup> 4 Tr 1008-1009.

<sup>2248</sup> 4 Tr 1009; Ex. FLO-22.

<sup>2249</sup> 4 Tr 1012.

<sup>2250</sup> 4 Tr 1023.

<sup>2251</sup> Id.; Ex. FLO-42.

<sup>2252</sup> Id.

and Consumers Energy, and any other electric utility that has overlapping territory with DTE Gas and require comparative cost-benefit analysis between electrification and gas system reinvestment when sections of the gas system age out.<sup>2253</sup>

Regarding Mr. Cebulko' recommendation that DTE Gas measure several certain indicators of equity at the census block level, Mr. Koepfel states that the Commission should order DTE Gas to include other indicators in the proposed mapping tool, tracked at the census block level, including the following: the amount of capital investment in gas infrastructure, the amount of capital investment in electric infrastructure, the average age of gas distribution infrastructure, the average age of electric distribution infrastructure, the distribution system voltage of electric distribution infrastructure, the hosting capacity of electric distribution infrastructure, gas system reliability performance data, and electric system reliability performance data.<sup>2254</sup>

Mr. Schott states that DTE does not have a coherent approach to addressing energy affordability, and it appears it has no intentions of adopting one, noting that DTE Gas has not conducted any affordability analysis when it develops its rate requests.<sup>2255</sup>

Mr. Schott states that DTE Gas does not analyze why so few of its low-income customers are enrolled in assistance programs like the Residential Income Assistance (RIA) credit.<sup>2256</sup> He adds that more than 400,000 DTE Gas LMI customers should be receiving the RIA credit but do not because DTE fails to make efforts to enroll them.<sup>2257</sup>

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<sup>2253</sup> 4 Tr 1040.

<sup>2254</sup> 4 Tr 1049.

<sup>2255</sup> Id.; Ex. FLO-45.

<sup>2256</sup> 4 Tr 1069.

<sup>2257</sup> 4 Tr 1070. Citation omitted.

Mr. Schott states that DTE's proposed rate increase would disproportionately impact LMI customers, noting that the requested 9% rate increase will exacerbate energy burdens for low-income customers that in many cases already exceed 15%, while the vast majority of customers with incomes above the median would still have energy burdens below 3%.<sup>2258</sup> Mr. Schott states that DTE's proposed allocation of costs relies on a 30.3% increase in the fixed monthly customer charge, from \$13.50 to \$17.60, compared to a 9% increase to the overall bill.<sup>2259</sup> He adds that fixed charges are a disincentive to conserve energy when a lower proportion of the bill is allocated to supply and distribution charges.<sup>2260</sup>

Mr. Schott states that 59% of DTE gas and electric residential customers earning less than 30% of Area Median Income (AMI) have extreme energy burdens of 15% or more, noting that many of these households are likely already using less energy than they need.<sup>2261</sup> He adds that 45% of Michigan households earning less than \$25,000 keep their home at an unsafe or uncomfortable temperature, and 35% of households earning from \$25,000– \$34,999 also do so.<sup>2262</sup>

Mr. Schott states that DTE Energy shut off customers more than 717,000 times from 2020 to 2023, and that DTE's shutoffs, both the rate and total number, far exceed even the practices of its investor-owned peers.<sup>2263</sup> He adds that enrollment in DTE's

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<sup>2258</sup> 4 Tr 1076. Citations omitted.

<sup>2259</sup> 4 Tr 1077. Citation omitted.

<sup>2260</sup> *Id.*

<sup>2261</sup> 4 Tr 1091; Ex. FLO-136.

<sup>2262</sup> *Id.*

<sup>2263</sup> 4 Tr 1097.

affordable payment plans has declined precipitously, dropping 63% between 2020 and 2023, noting that the reason for this decline is not clear.<sup>2264</sup>

Mr. Schott identifies numerous problems with DTE's shutoff notices, including that not all of the bills provide due dates to avoid shutoffs; despite DTE's assertions, the bills provide no information about programs that customers may be eligible for or strategies to reduce their bills; the bills do not provide the fees for reconnection; the payment amounts required to prevent a shutoff vary substantially; and the deposit requirements to restore service once a shut off has occurred vary substantially.<sup>2265</sup> Mr. Schott states that a systematic approach to reducing shutoffs could include a) enacting an immediate moratorium on all shutoffs not related to theft or unauthorized use, b) defining measures of success, namely a reduction in shutoffs and a reduction in the number of customers with energy burdens above 6%, c) proposing a comprehensive affordability strategy, d) creating a unified affordability program that reduces customer arrearages and enables customers to afford their bills, or expanding existing bill assistance programs significantly and increasing the marketing of these programs substantially, and e) creating systems that prioritize outreach, enrollment, and program evaluations to maximize the effectiveness of the above programs.<sup>2266</sup>

Mr. Schott requests that the Commission require DTE Gas to begin producing reports by census tract and zip code as soon as possible, but no later than 90 days after the Commission order.<sup>2267</sup>

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<sup>2264</sup> 4 Tr 1098.

<sup>2265</sup> 4 Tr 1105.

<sup>2266</sup> 4 Tr 1121.

<sup>2267</sup> 4 Tr 1129.

In addition, Mr. Schott recommends that the Commission initiate an immediate pause on shutoffs as it collects further information through DTE's data reports and docket U-21570 initiated in response to PA 231, and that the Commission adopt an extended moratorium on shutoffs, with associated customer protections against late fees, additional deposits, and reconnection fees, if the analysis of this forthcoming data identifies entrenched inequities, insufficient affordability programs, or a sustained risk to public health.<sup>2268</sup> Mr. Schott recommends that the Commission reinstate the monthly reporting requirements that it initially repealed in Case No. U-20757; recommends that the Commission set a firm timeline for DTE to begin these reports by census tract and zip code; and recommends that the Commission require DTE to provide all reports in publicly accessible and analyzable format.<sup>2269</sup>

Mr. Cira-Reyes states that low-and-moderate income (LMI) and Black, Indigenous and people of color (BIPOC) households often face an enormous burden in paying their gas bills, which will only be exacerbated by DTE Gas's call for higher rates.<sup>2270</sup> Mr. Cira-Reyes states that as electrification occurs, communities that do not electrify are forced to pay for the fixed costs of maintaining the gas distribution infrastructure.<sup>2271</sup> He states that many LMI and BIPOC communities cannot afford to transition from gas appliances to electric ones on their own, but they also will not be able to support financially the last vestiges of the gas industry either.<sup>2272</sup>

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<sup>2268</sup> 4 Tr 1134. Citation omitted.

<sup>2269</sup> 4 Tr 1141-1142.

<sup>2270</sup> 4 Tr 1152.

<sup>2271</sup> 4 Tr 1157.

<sup>2272</sup> 4 Tr 1158.

Mr. Cira-Reyes states that in order to begin addressing the affordability gap, DTE Gas must replace its various, disjointed assistance programs with one unified, central program that ensures customers are not paying more for their energy bills than they can afford.<sup>2273</sup>

This PFD agrees with the parties that our society is undergoing a fundamental energy transition in which society is shifting away from fossil fuels and towards renewable forms of energy. This PFD also agrees that this energy transition may result substantial reductions in the amount of gas delivered. Moreover, this PFD finds that DTE has not made much if any assessment or study of how any energy transition will be accomplished and at what costs. This PFD agrees that that DTE's Gas Delivery Plan is a good avenue to set forth its preliminary assessment of how it expects the transition to take place and what the resultant changes or ramifications may be for the utility and the ratepayers. Thus, this PFD recommends that the Commission direct DTE to update its Gas Delivery Plan to include its assessment of how, when, and at what cost, the transition may occur.

CEO recommends that the Commission order DTE to use the MiEJScreen tool to inform its capital investment decisions and the design and implementation of its customer programs in its next rate case.<sup>2274</sup> (4T 756–757). Cebulko states that by identifying geographic areas that may be under-served in terms of investment and/or programs, DTE can better target capital investments or programming directly to these areas, thereby meeting its obligation to provide service equitably.<sup>2275</sup> He claims that implementation of the MiEJScreen tool will inform DTE of the impact of its capital investment decisions on

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<sup>2273</sup> Id.

<sup>2274</sup> 4 Tr 756-757.

<sup>2275</sup> 4 Tr 755.

low income and environmental justice communities. Thus, he recommends that the Commission order DTE to immediately start using the tool to plan, develop, and implement its programs and capital investment decisions.<sup>2276</sup>

DTE counters that it believes that the existing methodology for risk and prioritization is appropriate, reasonable, and prudent for capital investment decisions.<sup>2277</sup>

Mr. Decker states that DTE intends to explore how the MiEJScreen Tool can be incorporated into its existing planning process and that DTE will outline its findings in the Gas Distribution Plan included in the Company's next rate case filing.<sup>2278</sup>

Similarly as to DTE's energy assistance programs, this PFD finds that many of the stated criticisms regarding affordability are well-taken and should be further evaluated for the Commission's consideration. Indeed, as indicated, *supra*, this PFD notes that Staff is not persuaded that DTE provides the comprehensive analysis and diverse, collaborative input the Commission is looking for to inform utility energy assistance changes. However, this PFD finds that many of the issues raised are currently being addressed in the EAAC workgroups. For example, regarding FLO's assertion that DTE Gas must replace its various, disjointed assistance programs with "one unified, central program" that ensures customers are not paying more for their energy bills than they can afford, Staff points out that this is what the EAAC's Affordability, Alignment, and Assistance subcommittee is currently working on. Moreover, this PFD finds that some of the proposals made by the parties in this case would benefit from further analysis and informed decision-making. For example, regarding FLO's proposal that the Commission should order DTE to cap

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<sup>2276</sup> 4 Tr 756.

<sup>2277</sup> 2 Tr 139.

<sup>2278</sup> 2 Tr 139-140.

settlement amounts for BudgetWise billing tied to what the household can afford to pay, Staff points out that this proposal essentially is unworkable, as determining how much a household is able to pay under this particular tariff is effectively unknowable and as there are issues with the ambiguity of what “ability to pay” means. Thus, this PFD finds it is premature to address these issues or adopt proposals made based on this record in this rate case. This PFD agrees with Staff that collaborative discussions with interested/invested parties in the EAAC workgroups as well as all investor-owned utilities will lead to the most informed positions and decisions on these issues such that any final assessments and changes by the Commission should await the completion of the work by the EAAC.

### **Tariff Changes for All Customers**

DTE summarized tariff changes in Exhibit A-16, Schedule F5. Revised tariff pages can be found in Exhibit A-16, Schedule F5.1.

ABATE recommends that DTE change the language under Section C3.3.D.1.a governing base period volumes for System Supply Customers to be the same as what is currently in Consumers Energy Company’s tariff.<sup>2279</sup> Ms. York suggests that the following language be added to the end of Section C3.3.D.1.a:

The customer shall notify the Company of any adjustment to base period volumes using any reasonable method of the customer’s choice, including but not limited to written request, phone call, or email. The Company shall notify the customer if the base period adjustment is accepted or rejected within 60 days of the request. A failure to affirmatively notify the customer shall be treated as an acceptance. If the requested adjustment is rejected, the Company shall provide the customer a written explanation detailing the reasons for the rejection. A customer may request an adjustment to its base period volumes two (2) times during a calendar year.<sup>2280</sup>

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<sup>2279</sup> 4 Tr 1293.

<sup>2280</sup> 4 Tr 1293, citing 6CEC’s gas tariff (MPSC No. 3), Second Revised Sheet No. C-11.00. Effective October 1, 2022.

She claims that her suggested modifications to Section C3.3.D.1.a will ensure that DTE's customers have the same level of flexibility with respect to adjustments to base period volumes as Consumers Energy Company's customers.<sup>2281</sup>

DTE disagrees with this suggested tariff revision, asserting that the proposed language would require DTE to be able to administer base period volume change requests from System Supply customers – customers who are largely non-contract customers that have a simplified relationship with DTE as compared to EUT customers - - and would also require DTE to spend resources to analyze, record, and recall the data upon a curtailment event for System Supply customers.<sup>2282</sup> DTE adds that given that most System Supply customers are the last to be curtailed, DTE believes the proposed tariff changes would result in a poor use of resources and would ultimately provide very little real-world benefits.<sup>2283</sup>

This PFD agrees with ABATE, finding that it is reasonable to provide DTE's customers with the same level of flexibility with respect to adjustments to base period volumes as Consumers' customers. Thus, this PFD recommends that the Commission adopt ABATE's proposed tariff revision.

### **Tariff Changes for Sales Rate Schedules**

DTE proposes the following changes under Section D of its rate book: a revised IRM; changes to the RIA credit and the LIA Credit; and DTE's proposed monthly customer charges and distribution charges for each rate schedule. The tariff sheet modifications are reflected in Exhibit A-16, Schedule F5 and the revised tariff pages can be found in

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<sup>2281</sup> Id.

<sup>2282</sup> 2 Tr 135-136.

<sup>2283</sup> 2 Tr 136.

Exhibit A-16, Schedule F5.1. DTE these changes should be accepted as no party opposes the changes.

Staff notes that it is standard practice to have the tariff reflect the Commission's decision in the rate case once it is made. Staff asserts that this means the RIA credit amount should reflect the Commission's ordered residential customer charge and the LIA credit amount in the tariff should reflect whatever the Commission approves. For these reasons, Staff states that the Commission should not consider these issues uncontested as DTE claims, but rather have the tariff reflect the Commission's decisions.

This PFD agrees with Staff.

#### **Tariff Changes for Sales Customers**

The tariff sheet modifications are reflected in Exhibit A-16, Schedule F5 and the revised tariff pages can be found in Exhibit A-16, Schedule F5.1.

#### **Tariff Changes for EUT Service**

The changes to these tariff pages include DTE's proposed Monthly Customer Charges and Transportation Rates for rates ST, LT, XLT, and XXLTL, which are reflected in Exhibit A-16, Schedules F5 and F5.1.

#### **Tariff Changes for Off-System Storage and Transportation Service**

DTE is proposing to increase the TOS-F (Section E25) and TOS-I (Section E26) not to exceed rate from \$0.4233 per MMBtu to \$0.5410 per MMBtu as set forth on Exhibit A-16, Schedule F6. DTE replaced the Gas Quality requirements in E17 with a reference to Section E3 Gas Quality which defined the Gas Quality requirement earlier in the tariff. Sections relating to Off-System Storage and Transportation was ANR, ML7 was removed from Imbalance and Penalty Charges paragraphs in Sections E25, 2 E26, E27, and E28.

## **Proposed Monthly Customer Charges and Rate Schedule Economic Break-Even Points**

DTE Gas proposes a \$17.60 monthly customer charge for residential Rate A.<sup>2284</sup> To maintain historical consistency, DTE asserts that the same charge should apply to the Rate 2A-Meter Class 1, and the monthly customer charge for Rate 2A-Meter Class II and Rate GS-1 should be set at \$50.00.<sup>2285</sup> DTE established the monthly customer charges for the remaining rate schedules by using the economic break-even points and proposed Rate GS-1 monthly customer charge.<sup>2286</sup> The Rate GS-2 monthly service charge is \$925.00, the Rate S monthly service charge is \$275.00, and the monthly customer charges for EUT Rates ST, LT, XLT, and XXLT are \$3,300.00, \$9,100.00, \$20,000.00, and \$230,000.00, respectively.<sup>2287</sup>

Staff takes issue with DTE's method of splitting test-year capital into separate accounts or categories using historical ratios, arguing that this approach is not acceptable given that cost compositions change year-to-year, such that DTE's calculation fails to reflect projections of costs appropriate for inclusion in the customer charge.<sup>2288</sup> Staff instead proposes to use historical adjusted costs, rather than projected test-year costs, to calculate the monthly customer charge for the residential class, utilizing only historical costs ensures that DTE's method of spreading projected costs does not include costs that are inappropriate for inclusion in the customer charge. Staff asserts that while using this methodology, Staff calculates a residential monthly customer charge of \$14.50.<sup>2289</sup>

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<sup>2284</sup> 2 Tr 98-99; Ex. A-16, Sch. F2.

<sup>2285</sup> 2 Tr 99; Ex. A-16, Sch. F2.

<sup>2286</sup> *Id.*

<sup>2287</sup> 2 Tr 99; Ex. A-16, sch. F2.

<sup>2288</sup> 4 Tr 1721.

<sup>2289</sup> *Id.*

DTE counters that its current method for splitting distribution plant using historical ratios is a common practice in cost-of-service and is a reasonable approach that reflects investments made in DTE's distribution system.<sup>2290</sup> Mr. Krysinski states that not all costs embedded in the residential customer charge rely on historical ratios as customer service costs reflect test-year cost projections made at the account level, and that no evidence has been provided demonstrating that the current approach results in inaccurate costs or that customers have been harmed.<sup>2291</sup> He adds that using historical costs for one subpart of rate design while otherwise using forecasted costs and determinants is broadly inconsistent.<sup>2292</sup>

The Attorney General recommends that the Commission instead either maintain the current residential (Rate A and 2A-1) monthly charge of \$13.50, and the current Rate GS-1 charge of \$40.00, or limit the monthly service charge increases to no more than \$1.00, to \$14.50.<sup>2293</sup> DTE asserts that the Attorney General's proposed level of customer charges for these rate classes is not supported by cost-based calculations and does not align with accepted regulatory practice.<sup>2294</sup>

As discussed, *supra*, this PFD recommends that the Commission adopt Staff's recommendations of the following customer charges: Residential - \$14.50, School - \$270.00, and GS-1 \$50.00, with all other customer charges being determined by rate design. Again, this PFD notes that Staff's proposed Residential charge of \$14.50 coincides with the alternative charge proposed by the Attorney General.

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<sup>2290</sup> 4 Tr 2173.

<sup>2291</sup> *Id.*

<sup>2292</sup> *Id.*

<sup>2293</sup> 4 Tr 1569.

<sup>2294</sup> 4 Tr 2175.

Mr. Decker states that the proposed economic break-even points between the various rate schedules are as follows:

GS-1 to GS-2 14,000 Mcf per year

GS-1 to S 2,183 Mcf per year

GS-1 to ST 14,500 Mcf per year

ST to LT 100,000 Mcf per year

LT to XLT 700,000 Mcf per year

XLT to XXLT 3.5 Bcf per year.

DTE asserts that the minimum optional rate under rate schedules ST and LT should remain at \$0.23 per Mcf, and that the minimum optional rate under rate schedules XLT and XXLT should remain at \$0.18 per Mcf and \$0.05 per Mcf, respectively.

### **Individual Customer Attachments**

DTE's Customer Attachment Program (CAP) is designed to enable the expansion of cleaner, safer, more reliable, and more affordable gas to new customers.<sup>2295</sup> The CAP also offers a financing mechanism for customers to avail gas services.<sup>2296</sup> Under the CAP, the costs of installing the necessary facilities for expansions are charged to new customers, with these costs being balanced by the revenue generated by the newly attached customers over a period of twenty years.<sup>2297</sup> DTE asserts that this extended timeframe allows for a more thorough evaluation of the financial feasibility of the expansion, noting that DTE and five other utilities participating in the CAP all align with the program by utilizing this twenty-year period.<sup>2298</sup>

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<sup>2295</sup> DTE initial brief, p. 165.

<sup>2296</sup> *Id.*

<sup>2297</sup> *Id.*, p. 165-166.

<sup>2298</sup> *Id.*, p. 166.

MNSC takes issue with the twenty-year period used to set rates. Mr. Hopkins asserts that it is likely that sales from new customer additions will fall over 20 years and thus that it is unreasonable for DTE Gas to set rates based on the assumption that gas use will remain constant over twenty years for all new customer attachments.<sup>2299</sup> Mr. Hopkins recommends that the Commission require DTE Gas to amend its tariffs and associated calculations to set a final date of 2034 – a ten-year period – beyond which DTE Gas will not provide any cost support for new customer attachments.<sup>2300</sup> He adds that DTE would also require customers to pay the net cost of the connection either up front or over a period that ends in or before 2034.<sup>2301</sup> He asserts that by reducing the assumed payoff period for assets built for new customers, DTE can increase the likelihood that new customers will in fact pay off the revenue deficiency before decarbonizing, accelerate the timeframe in which new customers contribute to shared utility system costs, and reduce the likelihood of stranded costs.<sup>2302</sup> He argues that ten years is a reasonable period from today because it gives time for the utility and customers to gradually transition and that by gradually removing subsidies year by year, this change should avoid market shocks while transitioning to a future in which existing customers are not subsidizing new customers to construct potential future stranded assets.<sup>2303</sup>

DTE counters that MNSC's recommended date of 2034 ignores the reality that existing homes will remain viable for more than twenty years.<sup>2304</sup> Mr. Abona states that customers have the means and the choice to decide whether they prefer natural gas or

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<sup>2299</sup> 4 Tr 858.

<sup>2300</sup> 4 Tr 859.

<sup>2301</sup> *Id.*

<sup>2302</sup> *Id.*

<sup>2303</sup> *Id.*

<sup>2304</sup> 3 Tr 396.

electrification and that currently, the cost of natural gas is still less than that of electricity.<sup>2305</sup> He adds that shifting from a twenty-year period to a ten-year period would place additional financial burdens on homeowners, thereby impacting housing affordability, citing a 2023 housing economics study which indicates that in Michigan, a \$1,000 rise in the median new home price (valued at \$375,352) would push an extra 4,521 households out of the market.<sup>2306</sup>

DTE also states that its CAP also includes community expansion projects, which extend DTE's natural gas infrastructure to underserved areas.<sup>2307</sup> Mr. Hopkins claims that overestimated the number of customer connections for fifteen projects by about fifty %.<sup>2308</sup> DTE counters that the customer connection data MNSC relies on in calculating the alleged shortfall in customer connections does not provide an accurate depiction of the total customer count spanning a period of five years as only four of the fifteen projects have been evaluated over a five-year period.<sup>2309</sup> This PFD notes that it previously found DTE's projections for these new market attachments to be unrealistic and thus unreasonable. See, discussion, *supra*.

This PFD agrees with DTE that imposing a ten-year period at this time is unreasonable. While MNSC's concerns about the transition in the utility industry potentially leading to a future in which existing customers are subsidizing new customers to construct potential future stranded assets are well taken – see discussion, *supra* – making the fundamental change that MNSC proposes without significant evidence

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<sup>2305</sup> 3 Tr 396-397; Ex. A-30, Sch. T2. Citation omitted.

<sup>2306</sup> 3 Tr 398.

<sup>2307</sup> DTE initial brief, p. 167.

<sup>2308</sup> 4 Tr 869.

<sup>2309</sup> 3 Tr 399.

supporting what the future holds for the housing market (whether and how much new customer additions may fall) and how the proposed changes may affect that market (whether and how much housing affordability may be impacted) is unreasonable. Thus, this PFD recommends that the Commission reject MNSC's proposal.

## **VII.**

### **REVENUE DEFICIENCY SUMMARY**

Based on the findings and conclusions discussed above, this PFD calculates revenue deficiency of \$97,950,000. See Appendix A.

## **VIII.**

### **CONCLUSION**

Based on the foregoing discussion I recommend the Commission issue an order which adopts the findings, recommendations, and conclusions provided in this PFD.

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

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Jonathan F. Thoits  
Administrative Law Judge

Issued and Served:  
September 4, 2024

Michigan Public Service Commission  
DTE Gas Company  
Projected Revenue Deficiency (Sufficiency)  
Projected 12 Month Period Ending September 30, 2025  
(\$000)

Appendix A  
PFD  
Case. No. U-21291

Line No.	(a) Description	(b) Source	(c) Applicant Projection	(d) PFD Adjustment	(e) PFD Projection
1	Rate Base	Exh. A-12, Sch. B1	\$ 6,939,800	\$ (137,779)	\$ 6,802,021
2	Projected Net Operating Income	Exh.A-13, Sch. C1	225,635	85,497	311,133
3	Overall Rate of Return	Line 2 ÷ Line 1	3.25%	1.32%	4.57%
4	Required Rate of Return	Exh. A-14, Sch. D1	6.04%	-0.41%	5.64%
5	Income Required	Line 1 x Line 4	\$ 419,337	\$ (35,899)	\$ 383,437
6	Income Deficiency / (Sufficiency)	Line 5 - Line 2	\$ 193,701	\$ (121,397)	\$ 72,304
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	1.3547	0.0000	1.3547
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	<u>\$ 262,407</u>	<u>\$ (164,457)</u>	<u>\$ 97,950</u>

**Michigan Public Service Commission**  
**DTE Gas Company**  
**Projected Rate Base**  
**For the 13-Month Average Period Ending September 30, 2025**  
**(\$000)**

**Appendix B**  
PFD  
Case. No. U-21291

	(a)	(b)	(c)	(d)	(e)
<b>Line No.</b>	<b>Description</b>	<b>Source</b>	<b>Applicant Projection</b>	<b>PFD Adjustment</b>	<b>PFD Projection</b>
1	Plant in Service	Exh A-12, Sch B2, L6	8,493,975	(101,201)	8,392,774
2	Plant Held for Future Use	Exh A-12, Sch B2, L7	-	-	-
3	Construction Work in Progress	Exh A-12, Sch B2, L8	<u>298,542</u>	<u>(35,983)</u>	<u>262,558</u>
4	Total Utility Plant		8,792,516	(137,185)	8,655,332
5	Less: Depreciation Reserve	Exh A-12, Sch B3, L7	<u>2,756,737</u>	<u>(10,367)</u>	<u>2,746,370</u>
6	Net Utility Plant		6,035,780	(126,818)	5,908,962
7	Net Capital Lease Property	Exh A-12, Sch B4.1, L8	-	-	-
8	Gas Stored Underground - non current	Exh A-12, Sch B4.1, L10	<u>35,303</u>	<u>-</u>	<u>35,303</u>
9	Total Utility Property and Plant	Line 6 + Line 7 + Line 8	6,071,082	(126,818)	5,944,264
10	Less: Capital Lease Obligations	Exh A-12, Sch B4.1, L69	<u>-</u>	<u>-</u>	<u>-</u>
11	Net Plant	Line 9 + Line 10	6,071,082	(126,818)	5,944,264
12	Allowance for Working Capital	Exh A-12, Sch B4 , L71	<u>868,717</u>	<u>(10,961)</u>	<u>857,757</u>
13	Total Projected Rate Base	Line 11 + Line 12	<u><u>6,939,800</u></u>	<u><u>(137,779)</u></u>	<u><u>6,802,021</u></u>

Michigan Public Service Commission  
DTE Gas Company  
Development of Projected Net Operating Income  
Projected 12 Month Period Ending September 30, 2025  
(\$000)

Appendix C  
PFD  
Case. No. U-21291

Line No.	(a) Description (Witness)	Revenue				Expenses											NOI			
		(b) Distribution Revenue	(c) Transport Revenue	(d) Other Operating Revenue	(e) Total	(f) Cost of Gas Sold	(g) Company Use & Lost Gas	(h) O&M	(i) Gas Uncollectibles	(j) Depreciation & Amort.	(k) Property Taxes	(l) Other General Taxes	(m) State & Local Income Tax	(n) FIT	(o) Other - Cust. Dep Interest	(p) Total	(q) NOI	(r) AFUDC	(s) Op. Income Adj.	(t) Adjusted NOI
<b>Company Filed</b>																				
	<b>Operating Income (Direct)</b>	973,937	111,644	143,784	1,229,365	-	43,209	538,251	35,149	243,219	114,068	16,870	8,889	8,948	406	1,009,009	220,356	4,680	(1,350)	223,685
	Distribution Rev. End User Trans	75			75								5	15		20	55			55
	Incentive Comp Amortization							(113)					7	22		(83)	83			83
	Shared Asset Deferral/ Amort (Rent)							(2,517)					165	494		(1,858)	1,858			1,858
	Interest Sync												12	35		47	(47)			(47)
1	<b>Operating Income (Initial Brief)</b>	974,012	111,644	143,784	1,229,440	-	43,209	535,621	35,149	243,219	114,068	16,870	9,078	9,513	406	1,007,134	222,306	4,680	(1,350)	225,635
<b>PFD Adjustments</b>																				
2																				
3																				
4	Removal of Responsibly Sourced Gas (RSG) Prem. (Royal)								(180)				12	35		(133)	133			133
5																				
6	Revenue & COGS - Offsetting Adj. (Todd)	(39,478)			(39,478)	(39,478)										(39,478)				
7																				
8	Incentive Compensation (McMillan-Sepkoski)							(12,147)					797	2,384		(8,967)	8,967			8,967
9	Restricted Stock (McMillan-Sepkoski)							(2,017)					132	396		(1,489)	1,489			1,489
10																				
11	Employee Savings Plan (Rueckert)							(1,683)					110	330		(1,242)	1,242			1,242
12	Uncollectibles Accounts Expense (Rueckert)								(14,470)				949	2,839		(10,681)	10,681			10,681
13																				
14	IT O&M - 20% disallowance related to 6 capital projects (Rogers)							(121)					8	24		(89)	89			89
15																				
16	Leak Detection and Repair (NPRM) (Creisher)							(10,276)					674	2,016		(7,585)	7,585			7,585
17																				
18	Company Gas Use & Lost Gas (AG)							(4,932)					324	968		(3,641)	3,641			3,641
19	Total O&M - Inflation (AG)							(4,001)					262	785		(2,953)	2,953			2,953
20	Total O&M - 2023 Cost Reduction							(22,431)					1,471	4,402		(16,558)	16,558			16,558
21	Total O&M - Voluntary Separation Savings							(2,350)					154	461		(1,735)	1,735			1,735
22	Pipeline Integrity (AG)							(6,670)					438	1,309		(4,924)	4,924			4,924
23	Active Health Care (AG)							(4,884)					320	958		(3,605)	3,605			3,605
24																				
25	Incentive Comp. - Operating Measures (AG)							(2,864)					188	562		(2,114)	2,114			2,114
26	Deferred OPEB Negative Expense (AG)							(9,734)					639	1,910		(7,185)	7,185			7,185
27	Corporate Jet Travel Costs							(75)					5	15		(55)	55			55
28																				
29	Corporate Memberships (FLO)							(1,779)					117	349		(1,313)	1,313			1,313
30																				
31	Impact of Cap Ex Adj on Depr Exp, Prop Tax, & AFUDC									(2,974)	(1,353)		284	849		(3,194)	3,194	(2,114)		1,080
32	Revert to prev. appr. Depr. Rates (Hecht)									(13,385)			878	2,626		(9,880)	9,880			9,880
33	Proforma Interest (Nichols)												(67)	(200)		(266)	266			266
34	Interest Synchronization (Nichols)																			
35	<b>Total Adjustments</b>	(39,478)	-	-	(39,478)	(39,478)	(4,932)	(81,212)	(14,470)	(16,359)	(1,353)	-	7,695	23,019	-	(127,089)	87,611	(2,114)	-	85,497
36	<b>PFD NOI - Test Year</b>	<b>934,534</b>	<b>111,644</b>	<b>143,784</b>	<b>1,189,962</b>	<b>(39,478)</b>	<b>38,277</b>	<b>454,410</b>	<b>20,679</b>	<b>226,860</b>	<b>112,715</b>	<b>16,870</b>	<b>16,774</b>	<b>32,532</b>	<b>406</b>	<b>880,045</b>	<b>309,917</b>	<b>2,566</b>	<b>(1,350)</b>	<b>311,133</b>

Michigan Public Service Commission  
DTE Gas Company  
Projected Rate of Return Summary  
Projected 12 Month Period Ending September 30, 2025  
(\$000)

Appendix D  
PFD  
Case. No. U-21291

Line No.	(a) Description	(b) Cost Rate Source from Exhibit A-14 Schedule	(c) Capital Structure		(e) % Amount of Total Capital	(f) Cost Rate %	(g) Weighted Cost of Permanent Capital (%)	(h) Weighted Cost of Total Capital (%)	(i) Pre-tax Multiplier	(j) Pre-tax Cost of Capital
			(c) 13 Mo. Avg. Amount (1)	(d) % Amount of Permanent Capital						
1	Long-Term Debt - net (2)	D2	\$ 2,749,081	50.00%	39.59%	4.44%	2.22%	1.76%	1.000	1.76%
2	Common Equity	D5	<u>2,749,081</u>	<u>50.00%</u>	39.59%	9.40%	<u>4.70%</u>	3.72%	1.355	5.04%
3	Sub-Total		<u>\$ 5,498,161</u>	<u>100.00%</u>			<u>6.92%</u>			
4	Short-Term Debt (3)	D3	\$ 184,380		2.66%	5.89%		0.16%	1.000	0.16%
5	Other Interest Bearing Credits									
6	Net Deferred Income Tax (4)		1,261,422		18.17%	- %		- %		- %
7	Deferred Investment Tax Cr.		-		- %	- %		- %		- %
	JDITC									
8	JDITC - Long-Term Debt		-		- %	4.44%		- %	1.000	- %
9	JDITC - Common Equity		-		- %	9.40%		- %	1.355	- %
10	Total JDITC		<u>\$ -</u>							
11	Total		<u>\$ 6,943,963</u>	<u>100.00%</u>			<u>5.64%</u>			<u>6.96%</u>

Michigan Public Service Commission  
DTE Gas Company  
Capital Expenditure and Rate Base Adjustments  
Projected 12 Month Period Ending September 30, 2025  
(\$000)

Appendix E  
PFD  
Case No. U-21291

Line	Adjustment Description	(a)	(b)	(c)	(d) (e) (f) (g) (h)					
		Total	Cap Ex Adj.	Plant in Svc	CWIP	Accum Dep.	Rate Base	Depreciation	Property Tax	AFUDC
1	<b><u>ROUTINE</u></b>									
2	Staff Distribution Plant - Service Renewals	(529)	(378)			(8)	(370)	(11)	(2)	
3	AG Distribution Plant - Main Renewals	(1,392)	(1,392)			(35)	(1,357)	(40)	(10)	
4	AG Distribution Plant - System Reliability	(13,592)	(10,306)			(221)	(10,084)	(293)	(61)	
5	AG Distribution Plant - Leak Detection Repair	(14,970)	(7,485)			(106)	(7,379)	(213)	(26)	
6	MNSC Distribution Plant - New Market Attachments - Mesick-Buckley CEP	(838)	(838)			(21)	(817)	(24)	(6)	
7	MNSC Distribution Plant - New Markets Attachments - Peach Ridge CEP	(912)	(912)			(45)	(867)	(26)	(19)	
8	AG Storage Plant - Gas Storage Compression	(13,325)	(11,416)			(226)	(11,189)	(279)	(73)	
9										
10	<b><u>LARGE CAPITAL PROJECTS</u></b>									
11	AG Traverse City Alpena Reinforcement Project	(3,000)	(3,000)			(128)	(2,872)	(47)	(81)	
12	AG Traverse City Alpena Reinforcement Project	(323)	(323)			(14)	(309)	(5)	(9)	
13	AG Fort Street Main Replacement	(32,753)			(16,377)		(16,377)		(837)	
14	AG Austin-Detroit A&B Lines	(21,007)			(12,917)		(12,917)		(915)	
15	AG Belle River-Detroit Interconnect and Loop	(8,125)			(4,436)		(4,436)		(242)	
16	AG Taggart Compressor Replacement	(4,000)			(2,254)		(2,254)		(120)	
17										
18	<b><u>INFRASTRUCTURE RECOVERY MECHANISM</u></b>									
19	ABATE Modified Main Replacement Program	(62,126)	(59,486)			(3,060)	(56,426)	(1,689)	(1,031)	
20	Staff Pipeline Integrity	(4,800)	(4,250)			(54)	(4,196)	(66)	(28)	
21										
22	<b><u>GAS INFORMATION TECHNOLOGY</u></b>									
23	AG Gas Scheduling Optimizer	(450)	(225)			(23)	(203)	(45)	(1)	
24	Staff Gas Information Technology	(1,756)	(1,191)			(166)	(1,025)	(238)	(7)	
25										
26	<b>TOTAL CAPITAL EXPENDITURE ADJUSTMENTS</b>	<b><u>(183,898)</u></b>	<b><u>(101,201)</u></b>		<b><u>(35,983)</u></b>	<b><u>(4,107)</u></b>	<b><u>(133,078)</u></b>	<b><u>(2,974)</u></b>	<b><u>(1,353)</u></b>	<b><u>(2,113)</u></b>
27	Staff <b><u>Adjust Case to Approved Depr. Rates in U-20118</u></b>					<b><u>(6,260)</u></b>	<b><u>6,260</u></b>	<b><u>(13,385)</u></b>		
28										
29	<b><u>WORKING CAPITAL ADJUSTMENTS</u></b>									
30										
31	Other Accounts Receivable						(301)			
32	Gas In Underground Storage						(9,133)			
33	Regulatory Assets - Shared Asset Deferral Mechanism						(1,304)			
34	I/C Accounts Payable						(223)			
35										
36	<b>TOTAL WORKING CAPITAL ADJUSTMENTS</b>						<b><u>(10,961)</u></b>			
37										
38	<b>TOTAL RATE BASE ADJUSTMENTS</b>						<b><u>(137,779)</u></b>			

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

\* \* \* \* \*

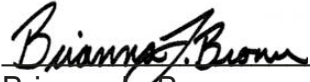
STATE OF MICHIGAN	)		
	)	SS.	Case No. U-21291
County of Ingham	)		
_____	)		

PROOF OF SERVICE

Meaghan Dobie being duly sworn, deposes and says that on September 4, 2024, 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

Subscribed and sworn to before me this  
4<sup>th</sup> day of September 2024.

  
\_\_\_\_\_  
Brianna L. Brown  
Notary Public, Gratiot County, Michigan  
My Commission Expires July 4, 2028

**Case No. U-21291**  
**Service List**

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Andrea E. Hayden

Breanna K. Reitzel

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