STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21973

In the matter of the application of	)
DTE GAS COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of natural gas,	)
and for miscellaneous accounting authority	)

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PUBLIC

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of
Attorney General Dana Nessel

March 13, 2026

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I. Introduction

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Sebastian Coppola. I am an independent business consultant. My office is at 5928 Southgate Rd., Rochester, Michigan 48306.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. I have testified in several regulatory proceedings before the Michigan Public Service Commission ("MPSC" or "Commission") and other regulatory jurisdictions. I have prepared and/or filed testimony in rate case proceedings, revenue decoupling reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power Supply Cost Recovery (PSCR) cases. As financial executive for two regulated gas utilities with operations in Michigan and Alaska, I have been intricately involved in business operations, regulatory proceedings related to gas cost recovery cases, gas purchase strategies, rate case filings, and cost analysis.

Q. PLEASE LIST SOME OF THE MORE RECENT CASES YOU HAVE PARTICIPATED IN BEFORE THE MPSC AND OTHER REGULATORY AGENCIES.

A. Here is a partial list of the most recent regulatory cases in which I have participated in the last two years:

- Filed testimony on behalf of the Michigan Attorney General in DTE Electric (DTEE) 2024 PSCR reconciliation in Case N-U-21426.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) proposed sale of hydroelectric power generating assets in Case No. U-21985.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2024-2025 GCR plan reconciliation in Case No. U-21446.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2024 PSCR reconciliation in Case N-U-21424.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2025 electric rate case U-21870 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2025 electric rate case U-21860 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2025-2026 GCR plan case No. U-21608.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-2024 GCR reconciliation in case No. U-21272.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 PSCR Plan Case No. U-21594.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2024 electric rate case U-21806 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2023-2024 GCR reconciliation in case No. U-21274.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 PSCR reconciliation in case No. U-21260.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR reconciliation in case No. U-21270.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan reconciliation in case No. U-21278.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21258.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2024 electric rate case U-21585 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2024 electric rate case U-21534 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2024 gas rate case U-21540 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2024 gas rate case U-21291 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2022-2023 GCR reconciliation case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in the Indian Michigan Power Company's 2023 electric rate case U-21461 on several issues,

including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

Appendix A elaborates further on my qualifications in the regulated energy field.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Michigan Attorney General (AG) to perform an independent analysis of DTE Gas Company's ("Company" or "DTE Gas") Rate Case filing in Case No. U-21973. This testimony presents a report of that analysis with related recommendations.

Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?

A. I am addressing the following major topics in this case:

1. The amount of End-User Transportation and Midstream revenues
2. The net margin from the Home Protection Plan (HPP)
3. Operations and maintenance expenses
4. Incentive compensation and deferred expense
5. Rate base and capital expenditures
6. The Main Replacement Program and IRM
7. The Company's proposal to include capital expenditures for Cathodic Protection, Pressure Regulators and new Meter Replacement programs in the IRM
8. Cost of Capital and Working Capital
9. Depreciation and Property Tax Expense
10. Customer Monthly Charges

The absence of a discussion of other matters in my testimony should not be taken as an indication that I agree with those aspects of DTE Gas's rate case filing. The narrow focus

of my testimony is, instead, a consequence of focusing on select issues within the available resources.

Q. IS YOUR TESTIMONY ON THESE TOPICS ACCOMPANIED BY EXHIBITS?

A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under my direct supervision:

1. Exhibit AG-1 DTE Energy Investor Presentation Information
2. Exhibit AG-2 CPI Forecast Publication
3. Exhibit AG-3 Main Renewals Units and Costs
4. Exhibit AG-4 Public Improvements Information
5. Exhibit AG-5 CONF Service Alterations
6. Exhibit AG-6 Meters and Modules Purchases, Ultrasonic Meters
7. Exhibit AG-7 CONF Customer Attachments
8. Exhibit AG-8 Distribution Pipeline Relocates Premature
9. Exhibit AG-9 Distribution Pipeline Premature Projects
10. Exhibit AG-10 Transmission South Grand Rapids Pipeline Replacement
11. Exhibit AG-11 Transmission East Petoskey Pipeline
12. Exhibit AG-12 Storage Columbus 23 Processing Project, Compressor Engines
13. Exhibit AG-13 Northen Operation Resource Center Renovation
14. Exhibit AG-14 Michigan Avenue Station Renovation
15. Exhibit AG-15 HPP Self-Service IT Portal
16. Exhibit AG-16 HPP System Enhancements Project
17. Exhibit AG-17 Gas Utility Network IT and MWM Enhancements Projects
18. Exhibit AG-18 Capital Expenditures, Depreciation, Property Taxes Disallowance
19. Exhibit AG-19 Working Capital Adjustments
20. Exhibit AG-20 Pre-Paid Property Taxes Payments
21. Exhibit AG-21 Overall Cost of Capital

22. Exhibit AG-22 Cost of Common Equity Capital
23. Exhibit AG-23 Cost of Common Equity Capital-DCF
24. Exhibit AG-24 Cost of Common Equity-CAPM
25. Exhibit AG-25 Cost of Common Equity-Risk Premium
26. Exhibit AG-26 Peer Group Analysis-Capital Structure
27. Exhibit AG-27 Market to Book Ratios
28. Exhibit AG-28 Gas ROE Decisions by Regulatory Commissions
29. Exhibit AG-29 DTE Gas Calculation of CFO Pre-WC to Debt Ratio
30. Exhibit AG-30 Peer Group ROEs
31. Exhibit AG-31 Rating Agencies Reports
32. Exhibit AG-32 Moody's July 27, 2025 Report
33. Exhibit AG-33 No Notice from Rating Agencies on Higher Capital Structure
34. Exhibit AG-34 CONF Nelson WP-24
35. Exhibit AG-35 Value Line Analysis of Stock Market Volatility
36. Exhibit AG-36 EUT Power Generation Volumes and EWR Reductions
37. Exhibit AG-37 CONF Midstream Storage Revenue Adjustment
38. Exhibit AG-38 Midstream Off-System Revenue Adjustment
39. Exhibit AG-39 Midstream Off-System Revenue Prior Years
40. Exhibit AG-40 Appliance Program Revenue and Margin 2019-2025
41. Exhibit AG-41 Other O&M Expense Adjustments Summary
42. Exhibit AG-42 O&M Expense Pipeline Integrity
43. Exhibit AG-43 O&M Expense Transmission ROW
44. Exhibit AG-44 Gas Leak and Work Management System Training
45. Exhibit AG-45 Damage Prevention Expense
46. Exhibit AG-46 Staking Leadership Expense
47. Exhibit AG-47 Regulator Station Maintenance Expense
48. Exhibit AG-48 Gas Refresher Training
49. Exhibit AG-49 Public Awareness Program
50. Exhibit AG-50 AG Inflation Adjustment
51. Exhibit AG-51 AG New Hire VEBA Adjustment

52. Exhibit AG-52 DTE Gas Calculation of VEBA Expense
53. Exhibit AG-53 DTE Gas Employee Savings Plan Expense Calculations
54. Exhibit AG-54 AG Savings Plan Expense Calculation
55. Exhibit AG-55 Employee Benefits Expense Comp to Prior Rate Cases
56. Exhibit AG-56 AG Healthcare Expense Adjustment
57. Exhibit AG-57 Healthcare Historical Costs
58. Exhibit AG-58 Incentive Comp Metrics Achieved 5 Years
59. Exhibit AG-59 AG Shared Assets Expense Calculation
60. Exhibit AG-60 Uncollectible Expense Adjustment
61. Exhibit AG-61 CONF Rate Case Expenses
62. Exhibit AG-62 IRM Cost Per Mile & Complex Projects, Cost Overruns
63. Exhibit AG-63 IRM Proposed Cost of Capital
64. Exhibit AG-64 AG Revenue Deficiency Calculation

II. SUMMARY CONCLUSIONS & RECOMMENDATIONS

Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND ADJUSTMENTS TO THE COMPANY'S REVENUE DEFICIENCY CALCULATION BEFORE YOU ADDRESS EACH TOPIC IN DETAIL.

A. The Company filed for a base rate increase of $237.4 million. However, after termination of the IRM surcharge pertaining to IRM investment rolled into rate base, the Company's proposed rate increase is $162.7 million, or 9%. As a result of the rate case adjustments I propose in my testimony, the net revenue deficiency is $34.8 million for an overall increase in rates of 2%. This result should not be surprising given the fact that the Company reported a revenue sufficiency of $38.2 million in the 2024 historical test year.

Based on my analysis of the Company's case, I have reached the following summary conclusions and recommendations:

1. I propose adjustments to increase end-user transportation service, midstream services, and other revenues, which reduce the Company's filed revenue deficiency by $24.3 million.
2. I propose a lower level of Operations and Maintenance expenses of $58.9 million for the test year.
3. I propose a reduction in capital expenditures of $193.5 million and a reduction in rate base of $157.5 million, including lower working capital, which reduce the revenue deficiency by $12.7 million.
4. I propose reductions in depreciation expense of $5.3 million and property taxes of $1.0 million, pertaining to the proposed reductions in capital expenditures.
5. I recommend an authorized rate of return on equity of 9.80%, in comparison to the Company's proposed ROE rate of 10.25%, and a permanent capital structure with 50% common equity and 50% long-term debt, which results in a reduction in the revenue deficiency of $26.7 million.
6. I recommend that the Commission terminate the IRM after 2027 or alternatively approve only a 3-year extension.
7. I recommend that the Commission reject the Company's proposal to expand the IRM to include Cathodic Protection, Ultrasonic Meter Conversion, and the Regulator Station Replacement programs.
8. I recommend that the Commission adopt a lower ROE rate for the cost of capital used in the IRM and make other related changes

9. I recommend that the Commission set the Residential Monthly Customer Charge at $15.40 and the Commercial GS-1 Monthly Charge at $53.00.

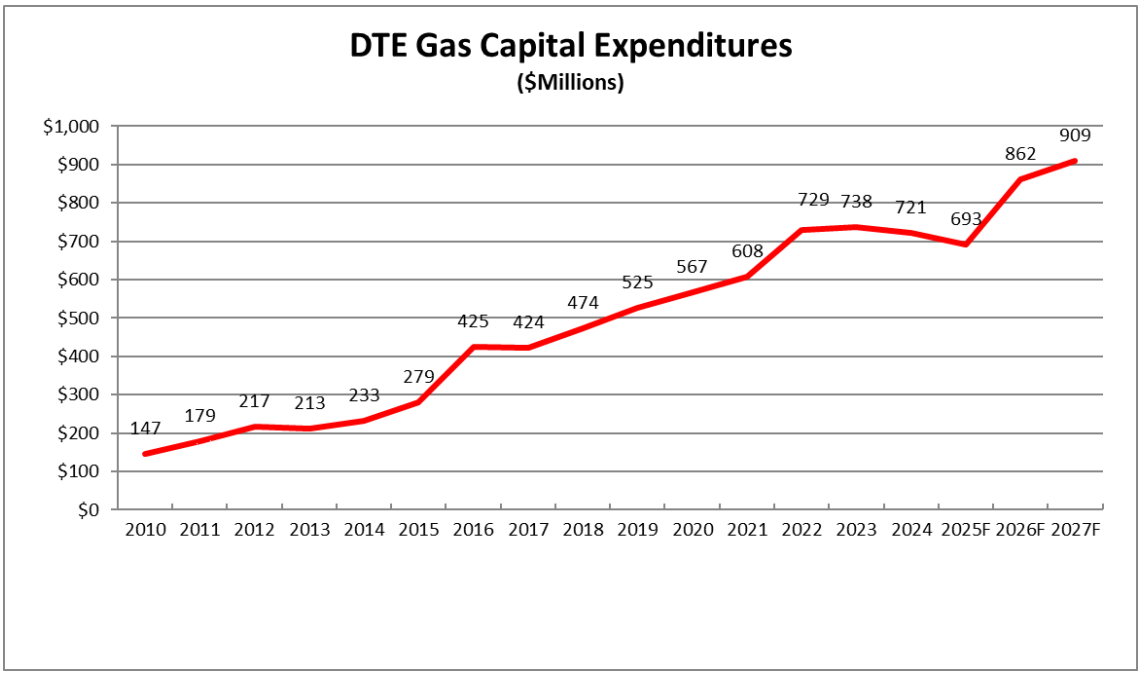
The remainder of my testimony provides further details and support for these summary conclusions and recommendations.

III. LARGE INCREASE IN RATE BASE AND CAPITAL EXPENDITURES

Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LEVEL OF CAPITAL EXPENDITURES PROPOSED BY THE COMPANY AND THE RESULTING INCREASE IN RATE BASE.

A. In this general rate case, DTE Gas reported $721 in capital expenditures for 2024 and proposes capital expenditures of $693 million for 2025, $646 million for the 9 months ending September 2026 ($861 million annualized), and $704 million for the 12 months ending September 2027. The total proposed capital expenditures over the 33-month period are nearly $2.1 billion.[1] In addition, the Company proposes to spend $2.1 billion from 2027 to 2031 on the IRM program on existing and new capital programs. These expenditures follow capital expenditures at similar levels during the prior three years from 2021 to 2023. The following chart in Table 1 shows the dramatic increase in capital expenditures over recent years, in comparison to more moderate amounts in prior years.

[1] Exhibit A-12, Schedule B5.



Until 2013, the Company was able to keep capital expenditures near or below $200 million annually. By 2016, annual capital expenditures had doubled and 10 years later have more than doubled again to $900 million.

The capital expenditures have fueled an alarming increase in rate base. As shown below in Table 2, rate base has been growing at double digit rates in recent years and the Company is proposing to increase rate base again in this rate case by 19%, to $8.0 billion. The proposed level of rate base in this rate case is nearly double the amount of rate base the Company had 9 years ago.

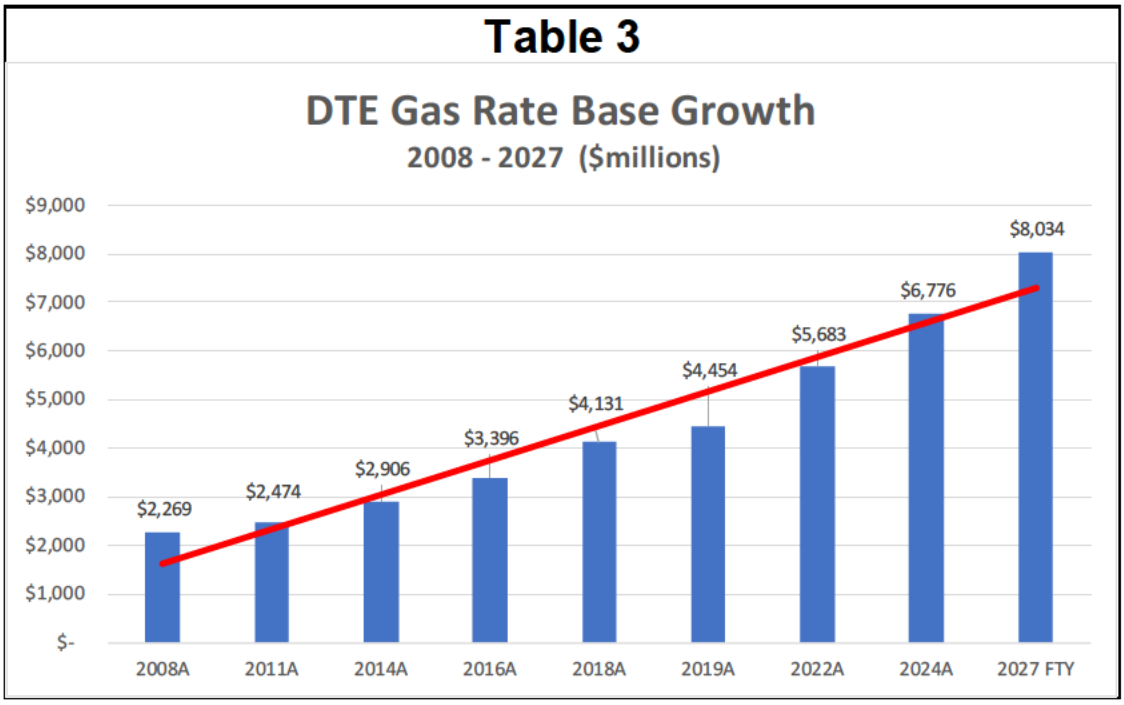
Table 2
DTE Gas Rate Base Growth
2008 to Projected 2027 Test Year

Rate Base Year	2008A	2011A	2014A	2016A	2018A	2019A	2022A	2024A	2027 FTY
Docket No.	U-15985	U-16999	U-17999	U-18999	U-20642	U-20940	U-21291	U-21973	U-21973
Rate Base [1] (Millions)	$ 2,269	$ 2,474	$ 2,906	$ 3,396	$ 4,131	$ 4,454	$ 5,683	$ 6,776	$ 8,034
Year over Year Change		9%	17%	17%	22%	8%	28%	19%	19%
Cumulative Change over 2008 Rate Base		9%	28%	50%	82%	96%	150%	199%	254%

[1] Historical actual rate base in each docket, except 2027 FTY is proposed amount.

This significant increase in rate base is illustrated by the following chart, included in Table 3, which shows the accelerated trend of increases in recent years. The current trend has significant negative implications for customer bills and bill affordability for all customers.

Table 3



Q. WHAT DO YOU BELIEVE IS DRIVING THIS DRAMATIC INCREASE IN CAPITAL EXPENDITURES AND RATE BASE?

A. I believe there are two main drivers. First, replacement of aging infrastructure and new capital spending to address market growth have required an increase in capital expenditures, which have accelerated investment to some degree. The Company continues to propose ever-increasing capital expenditures to replace cast iron mains, service lines, and related facilities. Some of this work is necessary and must be done. However, the Company has intensified the pace of replacement of pipelines and other facilities without sufficient engineering analysis to support the increase in capital expenditures.

The Company also seems to be experiencing moderate customer growth in its market area of approximately 10,000 customers annually. However, moderate customer growth has existed in prior years. Prior to 2013, DTE Gas was able to manage replacement of aging infrastructure and also invest in new facilities to meet market growth within a more reasonable increase in rate base. Therefore, customer growth and replacement of aging infrastructure by themselves do not fully explain the significant increase in capital expenditures and rate base since 2013.

Second, and perhaps a bigger driver, the replacement of aging gas infrastructure has given the Company an opportunity to accelerate rate base growth in order to increase earnings growth. For utility companies, earnings growth is directly related to rate base growth. As shown in the tables above, 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.

The Company'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%. Exhibit AG-1 includes pertinent pages from a February 2026 Investor Presentation, which show this drive to increase earnings through increased capital spending at the utility. For a utility such as DTE Gas with limited annual sales and revenue growth of less than 1%, the increase in earnings comes almost entirely from the increase in capital expenditures and rate base. The presentation is devoid of any discussion about sales or revenue growth to propel earnings growth at the utility.

Q. HAVE YOU DETERMINED WHAT THE IMPACT ON RESIDENTIAL CUSTOMER BILLS COULD BE OVER THE COMING YEARS IF THE COMMISSION APPROVES THE PROPOSED RATE INCREASE AND THAT RATE OF INCREASE CONTINUES INTO FUTURE YEARS?

A. Other witnesses testifying on behalf of the Attorney General are presenting bill impact information that reflects similar increases in capital spending and other operating cost increases.

IV. Review of Capital Expenditures

Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE CAPITAL EXPENDITURES COULD BE REDUCED?

A. Yes. I analyzed the Company's forecasted capital expenditures by major department or area, and I identified reasonable expenditure levels that the Commission should adopt. In projecting adjusted capital expenditures for the bridge period and the projected test year, where applicable, I applied an inflation factor to the historical cost base to reflect inflationary cost pressure that the Company may face in those years. The inflation factors are 2.74% for 2025, 2.4% for 2026, and 2.3% for 2027. These rates reflect the increase in the forecasted Consumer Price Index-Urban (CPI-U) for the 2025-2027 periods published in July 2025 and are the same CPI-U rates used by the Company in Exhibit A-13, Schedule C12.[2]

A. Distribution Plant

As shown on page 2 Exhibit A-12, Schedule B5.1, the Company forecasted capital expenditures for routine distribution facilities of $264.8 million for 2025, $255.6 million for the 9 months ending September 2026, and $322.9 million for the 12 months ending September 2027. After reviewing the testimony of Company witnesses Julia Huffman and Anna Jackson, related exhibits, and responses to discovery, I have identified capital expenditure reductions applicable to several areas.

[2] Exhibit AG-2 includes the publication with the forecasted CPI for 2025-2027 from S&P Global.

1. Main Renewals

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR MAIN RENEWALS.

A. As shown on page 2, line 3 of Exhibit A-12, Schedule B5.1, the Company had average capital expenditures of $6.6 million for main renewals during the 5 years from 2020 to 2024 and forecasted capital expenditures of $10.8 million for 2025, $3.5 million for the 9 months ending September 2026, and $6.3 million for the 12 months ending September 2027. On pages 9 through 11 of her direct testimony, Ms. Jackson briefly discusses the forecasted cumulative spending in this area over the 3-year period 2025-2027 in comparison to the 3-year historical period ended in 2024. She also points out the unplanned or emergent nature of the expenditures. The table with the number of units, capital spending, and unit cost from 2022 to 2027 shows forecasted costs increasing in 2025 and then declining in 2026 and 2027, with variances in the number of units from year to year and the unit cost peaking in 2025 at $334 per foot and declining to $212 in 2026 and 2027.

In discovery, the Attorney General asked the Company to provide the actual spending for 2025 with related units and the average cost per unit. The Attorney General also asked the Company to explain how the forecasted spending and number of units for 2026 and 2027 were determined. In the response, the Company provided the 2025 actual data, but no clear explanation as to how the forecasted number of units and capital expenditures were

determined.[3] The discovery response shows that for 2025 the Company replaced 16,769 feet of main at an actual cost of $3,173,000 and a cost per foot of $189. In comparison, the Company had forecasted capital expenditures of $10,777,000 for 2025 and installation of 32,264 feet of main at a cost per foot of $334.

Q. WHAT IS YOUR ASSESSMENT OF THE UNPLANNED MAIN RENEWAL PROGRAM?

A. The number of feet of main installed in 2025 was about half the number forecasted, at a much lower unit cost, and total expenditures of about one-third of the amount forecasted. The variance in capital spending between actual and forecast is $7,604,000. This large variance in forecasted spending has been included in the forecasted rate base in this rate case and should be removed. Customers should not pay for the depreciation expense and return on capital costs that were not incurred by the Company. In prior rate cases, the Commission has consistently removed underspent forecasted amounts from rate base and should do so again in this case. Therefore, I recommend that the Commission remove the $7,604,000 from the Company's forecasted 2025 capital expenditures and rate base.

To develop a reasonable forecast of capital expenditures for the 9 months ending September 2026 and the projected test year, I used the average number of feet of main installed in the most recent three years 2023-2025, which is 21,311 feet. To this number of units, I applied the Company's forecasted unit cost of $212 for 2026 and 2027. Although

[3] Exhibit AG-3 includes DR AGDG-4.136 Supplemental and 4.137a Supplemental with attachment.

this unit cost is higher than the most recent actual cost of $189 in 2025, I find it reasonable after adjusting it for future cost inflation. The result is forecasted capital expenditures of $4,518,000 for each year 2026 and 2027.[4] The amount applicable to the 9 months ending September 2026 is $3,389,000 ($4,518,000 x 9/12) and for the projected test year it is $4,518,000. In comparison, the Company forecasted higher capital expenditures of $3,530,000 for the 9 months ending September 2026 and $6,313,000 for the projected test year. The difference is $141,000 for the 9 months ending September 2026 and $1,795,000 for the 12 months ending September 2027.

Therefore, I recommend that the Commission remove capital expenditures of $7,604,000 for 2025, $141,000 for the 9 months ending September 2026, and $1,795,000 for the projected test year from the Company's forecasted capital expenditures.

2. Public Improvements

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR PUBLIC IMPROVEMENTS.

A. On page 2, line 4 of Exhibit A-12, Schedule B5.1, the Company shows average capital expenditures of $25.3 million for public improvements during the 5 years from 2020 to 2024 and forecasted capital expenditures of $23.9 million for 2025, $23.1 million for the 9 months ending September 2026, and $23.7 million for the 12 months ending September 2027. On pages 11-12 of her direct testimony, Ms. Jackson discusses the forecasted

[4] 21,311 units x $212 = $4,518,000.

cumulative spending in this area over the 33-month period ending in September 2027, in comparison to the 3-year historical period ended in 2024, and notes that the capital expenditures in this area are dependent on projects undertaken by government agencies in the public right-of-way (ROW), which often require relocation or changes to the gas lines located in the ROW. In her testimony, Ms. Jackson seems to indicate that the capital spending for the forecasted periods was developed based on the historical period 2022-2024, excluding the larger East Jefferson project.

In discovery, the Attorney General asked the Company to provide the historical and forecasted number of units, miles, or quantity of work performed in this expenditure category and the related spending for both the 2022-2025 historical years and forecasted periods. In response, the Company provided the list of projects and related dollars spent for the historical three years 2022 to 2025 and stated that it did not have a list of future projects past 2025.[5]

The capital spending of $20,999,000 in 2025 was $2,898,000 less than the forecasted amount $23,897,000. This large variance in forecasted spending has been included in the forecasted rate base in this rate case and should be removed. Customers should not pay for the depreciation expense and return on capital costs that were not incurred by the Company. As stated earlier, the Commission has consistently removed underspent forecasted amounts from rate base and should do so again in this case. Therefore, I

[5] Exhibit AG-4 includes DR AGDG-5.128.

recommend that the Commission remove the $2,898,000 from the Company's forecasted 2025 capital expenditures and rate base.

Q. ARE THERE SPECIFIC PROJECTS WITHIN THE FORECASTED CAPITAL EXPENDITURES FOR PUBLIC IMPROVEMENTS THAT SHOULD BE DISALLOWED?

A. Yes. On lines 4.7, 4.30, and 4.33 of page 1 of Exhibit A-12, Schedule B5.11, the Company shows three projects with large capital expenditures exceeding $1.0 million for 2026 and 2027. In discovery, the Attorney General asked the Company to identify the phase of development that each of the projects was currently in and the next phase of project development. In its response, regarding the Ford Lake Dam project, the Company stated the project was completing the design phase with construction bids being actively solicited and construction starting in May 2026. This project is sufficiently well advanced, and I do not recommend any cost disallowance.[6]

Regarding the I-375 Russell Bridge project, the projected is still in the preliminary assessment phase with the project planning and scoping phase not yet started and will not start until MDOT provides the Company with a construction plan.[7] This project is still in very early stages of development with considerable uncertainty on the timing and cost of the project. The total forecasted capital expenditures of $1,594,000 for 2026 should not

[6] Exhibit AG-8 includes DR AGDG-4.168.
[7] Id.

be included in rate base. Therefore, I recommend that the $1,195,000 of capital expenditures included in the 9 months ending September 2026 and the $398,000 included in the projected test year be removed from the Company's forecasted capital expenditures.

For the Ford Road Relocated project, the Company reported that this project was initially to be designed in 2026 and constructed in 2027 but delays in the MDOT construction schedule now pushed design of this project into 2027 and construction into 2028.[8] This project is also in the very early phase of development and premature to include in rate base in this rate case. The Company forecasted capital expenditures of $106,000 for 2026 and $2,372,000 for 2027. Therefore, I recommend that $80,000 of the capital expenditures pertaining to the 9 months ending September 2026 be removed along with the $1,805,000 for the 12 months ending September 2027 from the Company's forecasted capital expenditure.[9]

In summary, for Public Improvements, I recommend that the Commission disallow capital expenditures of $2,898,000 from the Company's 2025 forecast, $1,275,000 for the 9 months ending September 2026, and $2,203,000 for the projected test year capital expenditures.

[8] Id.
[9] $106,000 x 9/12 = $80,000; $2,372,000 x 9/12 + 106,000 – 80,000 = $1,805,000.

3. Service Alterations

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR SERVICE ALTERATION PROJECTS.

A. On page 2, line 5 of Exhibit A-12, Schedule B5.1, the Company shows average capital expenditures of $26.9 million for system reliability projects during the 5 years from 2020 to 2024 and forecasted capital expenditures of $33.1 million for 2025, $24.6 million for the 9 months ending September 2026, and $36.3 million for the 12 months ending September 2027. On pages 14 through 15 of her direct testimony, Ms. Jackson discusses the forecasted cumulative spending in this area over the 33-month period ending in September 2027 in comparison to the 3-year historical period ended in 2024.

In her testimony, Ms. Jackson states the increase in capital spending for the forecasted periods reflects the change in scope of customer requests with more complex service alterations and with the Company also performing more cross-bore inspections to ensure that the directional drilling and installation of the gas service line has not bored through sewer and other utility lines.

In discovery, the Attorney General asked the Company to provide the capital spending, number of units, and unit costs for Service Alterations for the historical years 2022 to 2025 and forecasted for 2026 and 2027. The Attorney General also requested information on the percentage of complex service alterations performed and forecasted, and the number of bore inspections performed.

The information provided in the discovery responses shows that actual capital expenditures for 2025 were $28,479,000, which is $4,629,000 lower than the forecasted amount of $33,108,000.[10] This large variance in forecasted spending has been included in the forecasted rate base in this rate case and should be removed. Customers should not pay for the depreciation expense and return on capital costs that were not incurred by the Company. As stated earlier, the Commission has consistently removed underspent forecasted amounts from rate base and should do so again in this case. Therefore, I recommend that the Commission remove the $4,629,000 from the Company's forecasted 2025 capital expenditures and rate base.

Regarding the other forecasted periods, the historical data provided by the Company shows that for the most recent three years, the average number of projects completed annually was 6,050 at an average unit cost of $5,156. In contrast, the Company has forecasted 6,430 units for 2026 and 6,760 units for 2027 at a unit cost of $5,284.[11] Although I find the forecasted unit cost reasonable, the forecasted number of units was not explained or justified and does not reflect more recent trends in work activity in the three years 2023-2025.

To determine a reasonable forecast for future periods, I used the 2023-2025 average units of 6,050 and multiplied them by the Company's forecasted unit cost of $5,284. The result is forecasted capital expenditures of $23,976,000 for 9 months ending September 2026

[10] Exhibit AG-5 CONF includes DR AGDG-4.141a Supplemental.
[11] Id.

($31,968,000 x 9/12) and $31,968,000 for the projected test year.[12] These amounts are $661,000 and $4,355,000 lower than the Company's forecasted amounts of $24,637,000 for the 9 months ending September 2026 and $36,323,000 for the 12 months ending September 2027.

Regarding the claim that the number of complex service alterations are increasing, the data provided by the Company in discovery shows that for the three years 2023-2025, the percentage of complex service line upgrades averaged 24.3% of the total number of service line alterations. For 2026 and 2027, the Company forecasted a similar 24% rate.[13]

For cross-bore inspections, the number of inspections in 2025 declined to 941 from 1,595 in 2024 and were approximately 1,250 in the prior two years.[14] The average number of annual cross-bore inspections during 2023-2025 was 1,273. This number is only 94 lower than the 1,367 inspections forecasted by the Company for 2026 and 2027.

In summary, contrary to the Company's claims, these two items are not making a significant impact on future capital expenditures for the forecasted periods in comparison with the most recent historical three-year period. Therefore, I recommend that the Commission remove $4,629,000 for 2025, $661,000 for the 9 months ending September

[12] 6,050 units x $5,284 = $31,968,000.
[13] Exhibit AG-5 CONF includes DR AGDG-4.141c.
[14] Id. includes DR AGDG-4.141d.

2026, and $4,355,000 for the 12 months ending September 2027 from the Company's forecasted capital expenditures.

4. Communications & Control - Meters

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR COMMUNICATIONS & CONTROL - METERS.

A. As shown on page 2, line 10 of Exhibit A-12, Schedule B5.1, the Company had average capital expenditures of $17.8 million for communication and control meters during the 5 years from 2020 to 2024 and forecasted capital expenditures of $17.8 million for 2025, $17.3 million for the 9 months ending September 2026, and $25.4 million for the projected test year. Beginning on page 24 of her direct testimony, Ms. Jackson discusses the drivers for the forecasted capital expenditures for meters and related equipment. The significant change discussed in the testimony is the Company's plans to replace existing diaphragm meters with new Ultrasonic Meters.

The Company's plans seem directed in two separate paths, (1) replacing existing meters as they fail, or related communication modules fail, with the new meters and (2) undertaking a complete meter replacement program through the IRM. With the installation of the new meters, the Company is also proposing to install a meter by-pass device that allows natural gas to flow to the house or business while work is being performed on the meter. Tables 5 and 6 on page 26 of Ms. Jackson's direct testimony show forecasted capital expenditures of $3.3 million for 2026 and $9.3 million for 2027

for routine replacement, with additional amounts forecasted to be spent under the IRM in 2026 and future years.

Exhibit A-12, Schedule B5.3, shows the amounts to be spent under the IRM and included in rate base for the 9 months ending September 2026 and the 12 months ending September 2027. Those amounts are $405,000 and $1,512,000, respectively. The $1,512,000 represents only the last three months of 2026 that have been included in the 12 months ended September 2027 test year with the full year IRM spending beginning in 2027. This segregation of costs is part of the confusing issue with the IRM integrating forecasted capital spending in different exhibits, which includes a portion of IRM expenditures in rate base up to the end of December 2026. In my analysis below, I will attempt to identify the total capital expenditures for this replacement program included in rate base for both routine replacements and replacements under the IRM.

In discovery, the Attorney General asked the Company to provide specific information of quantity and related costs by meter type, modules, and related equipment for each year 2022 to 2025 and forecasted for 2026 and 2027. The granular information provided by the Company shows that the Company continued to install about 24,000 diaphragm meters and approximately 48,000 AMI/AMR modules in 2025. Some of those modules replaced failing modules. For 2026, the Company plans to replace and install another 24,000 diaphragm meters and 63,400 AMI/AMR modules. In addition, for 2026, the Company plans to install 7,500 ultrasonic meters at a cost of $2,070,000, or $276 each, and 7,500 meter bypass devices at a cost of $1,125,000, or $150 each. For 2027, the installation of

ultrasonic meters and bypass devices increases to 21,000 units with $5,794,000 forecasted to be spent on the meters and $3,150,000 forecasted to be spent on the bypass devices.[15]

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PLANS TO MOVE TO ULTRASONIC METERS?

A. There are several issues that arise from the Company's sketchy proposal. First, in testimony in this case, the Company did not put forth a comprehensive program with the full cost of the replacement program from inception to completion. In response to discovery, the Company stated that it wants to use the initial rollout to gather information on meter and bypass performance in its territory, test field installations, and assess success and pain points.[16] This roll out sounds similar to a temporary pilot program. The rollout cannot be achieved without an additional investment in communication with IT software and hardware technology, which the Company has forecasted at least in the amount of $5.0 million to be spent over the bridge period and the projected test year.[17]

In response to discovery, the Company could not provide the total cost of the program from inception to completion or the replacement timeline.[18] Given the required investment in communication, this is not the type of program that can be stopped once started without the Company incurring stranded costs, which it would undoubtedly seek to recover from customers. A rollout or pilot program should be started only after the program has been

[15] Exhibit AG-6 includes DR AGDG-4.146a with related attachment.
[16] Id. includes DR AGDG-4.150j.
[17] Id. includes DR AGDG-4.150h and 4.150e. Also, Exhibit A-12, Schedule B5.4.1, line 25.
[18] Id. includes DR AGDG-4.150j.

fully defined, vetted, and approved so that the Commission and other parties to this rate case can understand the entire financial implications of the proposed meter replacement program.

Second, the ultrasonic meters represent new metering technology that has not been widely implemented in the gas utility industry. The Company identified five gas utilities that have started or completed installation of ultrasonic meters. This is still a relatively small group of utilities and there is insufficient experience in the field to identify problems that may arise with the new meter technology. Although in response to discovery the Company pointed out that the new meters are somewhat more accurate in metering gas flows, it could not identify the failure rate of new meters after they are installed or other complications.[19] It is always best not to adopt new technology too early and wait until it is well sorted out before taking on the pain of failures and higher costs.

Third, the Company states that the impetus for moving to the ultrasonic meters is to avoid the coming failures of the AMI and AMR modules attached to the current diaphragm meters. The Company anticipates that as the modules reach their 20-year life, the battery within the module, which cannot be separated and replaced from the module, will begin to fail. The Company forecasts 3,000 battery failures in 2026 and potentially reaching 153,000 by 2032.[20] In response to discovery, the Company disclosed that the initial

[19] Id. includes DR AGDG-4.148a, 4.150b, and 4.150f.
[20] Id. includes DR AGDG-4.147b.

installation of AMI/AMR modules on diaphragm meters began in 2008 and concluded in 2023.[21]

Therefore, thousands of the modules are still less than 10 years old and still have at least 10 more years to go to reach the projected 20-year end of life. From the information provided in DR AGDG-4.146a, the Company has been replacing thousands of the failing modules during the past few years and still plans to replace 63,400 modules in 2026 and 45,200 in 2027.[22] These replacements should last many more years. The cost to replace an AMI/AMR module is $74, in comparison to installing a new ultrasonic meter at $276.[23] Therefore, replacing failing modules is still more economic than replacing the entire meter with a new ultrasonic meter and the imbedded communication module.

Fourth, in discovery, the Attorney General asked the Company to explain the necessity and advantages to installing the bypass device with the new ultrasonic meters. In response, the Company stated that if a meter change would be needed in the future, the technician could replace the meter without shutting off the gas flow to the house or business and thus avoid scheduling an appointment with the customer. Although on the surface this option sounds convenient, there are several other issues that arise, including (1) the incremental cost of installing the device at $150 each, which over the entire customer base of 1.3 million customers would amount to $195 million, assuming no cost increases, (2) the

[21] Id. includes DR AGDG-4.150c.
[22] Id.
[23] 2026 AMI/AMR module cost of $4,711,000 ÷ 63,400 modules = $74.30.

frequency of the need to replace the meter is less than 2% over the life of the meter as expected on average for the entire customer base, and (3) the possibility that customers may discover a way to bypass the meter on their own, thus avoiding registering gas consumption until discovered by the Company.[24]

The Company also mentions emergency work as a benefit to having a bypass device to avoid inconveniencing the customer, but it seems that during emergency work the meter and service to the house or business should be shut off and the customer should be notified or involved. Also, the idea of a service technician performing work at the meter outside the house without notifying and involving the customer seems potentially dangerous. In summary, the limited benefits that a bypass device can provide do not justify the high cost.

Fifth, the Company did not perform a complete cost/benefit analysis (CBA) to economically justify the program. In response to discovery, the Company provided some preliminary projections of potential annual cost savings of $3.5 million to $4.5 million but no costs for the program from inception to completion. Without a comprehensive CBA, it is not possible to assess the economic viability of the program. The Company attempts to justify the lack of a CBA by opining on the need to replace the diaphragm meters and failing AMI/AMR modules, plus the need to gather more information through the rollout period.

[24] Exhibit AG-6 includes DR AGDG-4.146b, 4.150a, 4.150l, and 4.150m.

However, as discussed above, the replacement of failing modules can be done for several more years by replacing those failing modules at a lower cost with new AMI/AMR modules, as the Company has been doing in recent years. Additionally, the Company can prepare a CBA without first installing new ultrasonic meters. The research that the Company has done through discussions with vendors and other gas utilities that have begun installing ultrasonic meters should provide sufficient information to determine what the annual cost from inception to completion of the program would be and the related cost savings, if any.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION PERTAINING TO THE ULTRASONIC METER REPLACEMENT PROGRAM AND THE FORECASTED CAPITAL EXPENDITURES FOR COMMUNICATIONS AND CONTROL METERS?

A. As discussed above, the Company has not defined a comprehensive program to transition from diaphragm meters and AMI/AMR modules to ultrasonic meters. The total cost and timeline of the program are unknown, there is no cost/benefit analysis, and there is insufficient justification to undertake the program at this time. In summary, it is premature to include any of the proposed capital expenditures for the ultrasonic meters and bypass devices in this rate case and the IRM.

The Company has identified $3,195,000 in capital expenditures for 2026 and $8,944,00 for 2027. Prorated for the 9 months ending September 2026, the amount is $2,396,000

and for the 12 months ending September 2027 the amount is $7,507,000.[25] Therefore, I recommend that the Commission remove these amounts from the Company's proposed capital expenditures and forecasted rate base.

5. Customer - Market Attachments

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR CUSTOMER ATTACHMENTS.

A. As shown on page 2, line 13 of Exhibit A-12, Schedule B5.1, the Company had average capital expenditures of $81.8 million for customer attachments during the 5 years from 2020 to 2024 and forecasted capital expenditures of $82.7 million for 2025, $82.0 million for the 9 months ending September 2026, and $97.3 million for the 12 months ending September 2027. Beginning on page 38 of her direct testimony, Ms. Huffman briefly discusses the forecasted cumulative spending in this area over the 33-month period ending in September 2027 in comparison to the 2024 historical period. Ms. Huffman states that the Company forecasted new customer attachments of 10,041 for 2025, 11,895 for 2026, and 11,846 for 2027.

In discovery, the Attorney General and other parties asked the Company to provide the number of customer attachments in prior years and the calculations showing how the

[25] $3,195,000 x 9/12 = $2,396,000; $8,944,000 x 9/12 + $3,195,000 – 2,396,000 = $7,507,000. The Company has disclosed in Exhibit A-12, Schedule B5.4 that $405,000 of the total 9 months ending September 2026 amount and $1,512,000 of the total 12 months ending September 2027 amount has been included in rate base as a transfer from the IRM. The remainder for each period pertains to the routine replacement program that Ms. Jackson discusses in her direct testimony.

forecasted number of attachments were determined. In responses, the Company reported that the recent historical number of customer attachments was 9,990 in 2023, 11,068 in 2024, and 9,446 in 2025.[26] The average annual number of attachments during that three-year period was 10,168. This average level of attachments is about 1,700 lower than the Company's forecasted numbers of 11,895 for 2026 and 11,846 for 2027.

After reviewing the Company calculations to arrive at its forecasted numbers, it appears that the forecasts are overstated. In its calculations, the Company combines three sources of data. First, it used the total number of residential housing starts in Michigan forecasted by S&P Global Insights for 2026 and 2027 and multiplied those numbers based on the average percentage of gas market penetration in the Michigan residential energy market. Additionally, it applied the percentage share of DTE Gas customers to total gas customers in Michigan. These are broad assumptions that do not necessarily reflect the number of new attachments that occur in the Company's service area. For example, the number of attachments in the City of Detroit and in the Upper Peninsula, which have extremely low customer growth and perhaps even declines, do not rise to the same growth rates experienced in faster growing areas in the rest of the State of Michigan.

In the second step, the Company uses the average number of customers added during the five-year period 2020-2024 and takes the average of the attachments from steps 1 and 2. As a third step, the Company adds to this average the number of customers forecasted to

[26] Exhibit AG-7 CONF includes DR MECCUBDG-3.9 with attachments and DR CLC-2.1.

be added through on-main conversions, main extensions, and community expansions. The additions in Step 3 also may reflect some duplication with new construction, particularly in main extension projects.[27] In summary, this convoluted forecasting methodology does not result in an accurate projection. If the same approach had been used for 2025, it would have likely resulted in a forecast much higher than the 9,446 total customer attachments actually reported.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION FOR THE APPROPRIATE NUMBER OF CUSTOMER ATTACHMENTS AND RELATED CAPITAL EXPENDITURES FOR THE BRIDGE PERIOD AND PROJECTED TEST YEAR?

A. The average number of customer attachments in the most recent three years offers the best basis for forecasting the number of attachments for 2026 and 2027. The average number of attachments of 10,168 during the past three years is higher than the 9,446 reported for 2025, reflecting higher numbers in prior that could repeat in 2026 and 2027. The three-year average avoids any forecasting errors and any potential duplications inherent in the Company's forecast.

The Company forecasted a unit cost of $8,205 per customer attachment for the projected test year ($97,298,000 ÷ 11,858 units). This amount is higher than the actual unit cost of $7,563 in 2024 ($83,708,000 ÷ 11,068 units). However, allowing for inflation in 2026 and

[27] Id., includes the New Markets Attachments Forecast for 2025-2035.

2027, I find the $8,205 unit cost to be reasonable. By applying this unit cost to the 10,168 customer attachments, I determined capital expenditures of $62,571,000 for the 9 months ending September 2026 and $83,428,000 for the 12 months ending September 2027.[28] These amounts are $19,406,000 and $13,870,000 lower than the Company's forecasts for the respective periods.[29]

Therefore, I recommend that the Commission remove $19,406,000 for the 9 months ending September 2026 and $13,870,000 for the 12 months ending September 2027 from the Company's forecasted capital expenditures.

6. System Reliability Projects

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR SYSTEM RELIABILITY PROJECTS.

A. On page 4 of Exhibit A-12, Schedule B5.11, the Company shows several projects with large capital expenditures exceeding $1.0 million for 2026 and 2027. In response to discovery, the Company identified two projects that are still in the early stage of engineering design with construction not planned until the middle of 2027. Other projects listed in the discovery response are beginning construction in the upcoming months of 2026 and are well along in their phase of development.[30]

[28] 10,168 x $8,205 = $83,428,000 x 9/12 = $62,571,000.
[29] DTE Gas forecast of $81,977,000 for 9 months ending September 2026 and $97,298,000 for the 12 months ending September 2027 on line 13 of page 2 of Exhibit A-12, Schedule B5.1.
[30] Exhibit AG-9 includes DR AGDG-4.169.

Regarding the Euclid 60 PSI Huiber Main and McNichols & Greenfield projects, they are still in the early phase of development with the engineering design phase not yet completed and construction costs and the timing of construction still preliminary until the engineering design is completed. These projects are premature to include in rate base in this rate case. The Company forecasted $2,388,000 for 2027 for the Euclid Hiber Main project and $119,000 for 2026 and $2,533,000 for 2027 for the McNichols & Greenfield project.

I recommend that the Commission remove $89,000 for the 9 months ending September 2026 and a combined $3,721,000 for the projected test year.[31]

B. Transmission Plant

Transmission plant additions consist of both routine projects and large capital projects. Below, I will discuss adjustments to two large capital projects: the South Grand Rapids Pipeline Replacement and the East Petoskey Replacement.

1. South Grand Rapids Pipeline Replacement

As shown on line 8 of Exhibit A-12, Schedule B5, the Company forecasted capital expenditures for the South Grand Rapids Pipeline project of $1,333,000 for 2025, $12,759,000 for the 9 months ending September 2026, and $13,679,000 for the projected test year. Beginning on page 42 of her direct testimony, Ms. Kelly Fedele discusses this

[31] $119,000 x 9/12 = $89,000; $2,388,000 x 9/12 + $2,533,000 x 9/12 + 119,000 – 89,000 = $3,721,000.

project as the replacement of 2.6 miles of an aging 22-inch diameter transmission pipeline operating at 238 psig with a 3.1 mile, 24-inch, pipeline operating at 300 psig.[32]

The primary reason for replacement of the existing pipeline seems to be that the steel pipeline was manufactured by A. O. Smith & Company with a long horizontal seam that can be prone to corrosion and potentially rupture. In her testimony, Ms. Fedele states that due to the design of the pipeline, the Company cannot perform In Line Inspection (ILI) of the pipeline with a robotic tool and cannot perform pressure testing of the line. Additionally, the Company concluded that direct assessment of the condition of the pipeline would not discover potential cracking and weakness in the wrinkle bends of the pipeline.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSAL TO REPLACE THE SOUTH GRAND RAPIDS PIPELINE?

A. I find the Company's proposal inadequately justified and unsupported by sufficient and clear evidence to support the reasonableness of undertaking the project at this time at a cost in excess of $30 million through the end of 2027.[33] In discovery, the Attorney General asked the Company to identify the number of leaks reported on the pipeline in the last five years, provide evidence of the severity of wrinkles on the line, and identify the number of direct assessment digs performed along the pipeline.

[32] Line 8 of Exhibit A-12, Schedule B5, identifies this pipeline as distribution line, which creates some confusion.
[33] Exhibit A-12, Schedule B5.5, page 8.

In response, the Company stated that no gas leaks had been identified and reported on the pipeline in the last five years.[34] Regarding the severity of wrinkles on the line, the Company could not provide any specific information and instead provided photos of what typical wrinkles *could* look like on a pipeline of that size.[35] The Company also reported that it has four pipelines in its system with wrinkle bends and no ruptures have occurred in the last 10 years.[36]

Regarding direct assessment of the welded seam problem on the pipeline, the Company reported that, although some portions of the pipeline had been exposed for construction activities, no direct assessments or laboratory analysis of the pipe had been performed because the assessment of the pipeline is not due until 2029. In the response, the Company concluded that inspections of other pipelines of similar vintage had found some defects consistent with industry experience.[37]

The decision by the Company to undertake this project seems to be based almost entirely on circumstantial evidence of what has occurred with other similar pipelines. There is no direct evidence that a serious or imminent problem exists that requires a costly replacement of pipeline within the next year or two. The Company's statement that a direct assessment of the pipeline is not due until 2029 is befuddling. If the Company goes through with its plans to replace the pipeline now, the 2029 assessment cannot occur on the existing

[34] Exhibit AG-10 includes DR AGDG-3.109c.
[35] Id. include DR AGDG-3.111b.
[36] Id. includes DR AGDG-8.347.
[37] Id. includes DR AGDG-3.109b

pipeline. In response to discovery, the Company reported that between 2024 and 2025, it performed 7 direct assessments to assess external and internal corrosion on other pipelines.[38] A direct assessment with several digs along the pipeline and particularly in the areas where the wrinkles are located, combined with non-destructive testing and x-rays could confirm the integrity of the pipeline or discover sufficient deterioration to require repairs or justify full replacement. Without this information, the Company is proceeding on supposition and speculation about the true condition of the pipeline.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION ABOUT THE GRAND RAPIDS PIPELINE REPLACEMENT PROJECT AND THE RELATED FORECASTED CAPITAL SPENDING?

A. The Company has not presented an adequate case with compelling and convincing evidence that the project should be undertaken at this time. Therefore, I recommend that the Commission remove the capital expenditures forecasted by the Company in the amount of $1,333,000 for 2025, $12,755,000 for the 9 months ending September 2026, and $13,679,000 for the projected test year.

2. East Petoskey Pipeline Reinforcement

As shown on line 12 of Exhibit A-12, Schedule B5, the Company forecasted capital expenditures for the East Petoskey Pipeline Reinforcement project of $406,000 for 2025, $3,266,000 for the 9 months ending September 2026, and $32,168,000 for the projected

[38] Id. includes DR AGDG-8.348.

test year. Beginning on page 36 of her direct testimony, Ms. Kelly Fedele discusses this project as the construction of a new 13.5-mile transmission pipeline to connect with Great Lakes Gas Transmission Pipeline and provide another source of gas supply to the City of Petoskey and surrounding areas.

In response to discovery, the Company confirmed that the project has not yet received internal approval and is in the initial phase of engineering design. Due to the early stage of development and no internal approval, it is premature to include this project in rate base in this rate case. Therefore, I recommend that the Commission remove the forecasted capital expenditures of $406,000 for 2025, $3,266,000 for the 9 months ending September 2026, and $32,168,000 for the projected test year.

C. Gas Storage Plant

As shown on page 2, line 22 of Exhibit A-12, Schedule B5.1, the Company spent an average annual amount of $13.6 million on storage compression projects during the five years from 2020 to 2024 and forecasted capital expenditures of $11.3 million for 2025, $15.2 million for the 9 months ending September 2026, and $22.0 million for the projected test year. Included in the amount for the projected test year are the Columbus 23 Storage Gas Processing Unit Upgrade, the Belle River Mills Z5 Engine and Compressor Overhaul project, and the Belle River Mills Unit 8 Turbine Engine Exchange project.

Columbus Upgrade Project - Ms. Jackson discusses the Columbus 23 upgrade project beginning on page 47 of her direct testimony. The forecasted capital expenditures of this

project are $2,300,000 for the projected test year. In discovery, the Attorney General asked the Company to provide the total cost of the project from inception to completion and the current phase of development of the project. In response the Company stated that the project will occur in two separate phases at a preliminary total cost of $6.0 million.[39] Regarding the current phase of development, the Company stated that the project is in the project planning and scoping phase with the subsequent phase being engineering design.[40]

The Columbus 23 upgrade project is still in the very early stages of development going through project planning and scoping with no design yet completed. This project is premature to include in rate base in this rate case. I recommend that the Commission remove the $2,300,000 from the Company's forecasted capital expenditures for the projected test year.

Belle River Mills Z5 Engine & Compressor Overhaul - Ms. Jackson discusses the Belle River Mills Z5 Engine and Compressor Overhaul project beginning on page 52 of her direct testimony. The forecasted capital expenditures of this project are $6,100,000 for the projected test year. In discovery, the Attorney General asked the Company to provide the current phase of development of the project. In response the Company stated that the project is currently in the project planning and scoping phase with the subsequent phase being requesting competitive contract bids.[41]

[39] Exhibit AG-12 includes DR AGDG-4.155a.
[40] Id. includes DR AGDG-4.155d.
[41] Id. includes DR AGDG-4.157c.

The Belle River Z5 engine and compressor overhaul project is still in the very early stages of development going through project planning and scoping with no additional work completed. This project is premature to include in rate base in this rate case. I recommend that the Commission remove the $6,100,000 from the Company's forecasted capital expenditures for the projected test year.

Belle River Mills Unit 8 Engine Exchange - Ms. Jackson discusses the Belle River Mills Unit 8 Engine Exchange project beginning on page 55 of her direct testimony. The forecasted capital expenditures of this project are $6,000,000 for the projected test year. In discovery, the Attorney General asked the Company to provide the current phase of development of the project. In response the Company stated that the project is currently in the project planning and scoping phase with no subsequent phase identified.[42]

The Belle River Mills Unit 8 engine exchange project is still in the very early stages of development, going through project planning and scoping with no additional work identified past the current phase. This project is premature to include in rate base in this rate case. I recommend that the Commission remove the $6,000,000 from the Company's forecasted capital expenditures for the projected test year.

D. General Facilities and Structure Improvements

On page 2, line 24 of Exhibit A-12, Schedule B5.1, the Company shows capital expenditures for Structure and Improvements of $7.6 million on average from 2020 to

[42] Id. includes DR AGDG-4.158d.

2024 and forecasted capital spending of $2.8 million for 2025, $10.4 million for the 9 months ending September 2026, and $16.3 million for the projected test year. Beginning on page 61 of her direct testimony, Ms. Jackson discusses the spending in this area and identifies some of the major projects the Company plans to undertake in 2026 and into 2027. I will address two projects in this area, the Northen Operations Resource Center (NORC) and the Michigan Avenue Service Center Renovation.

Q. PLEASE DISCUSS THE NORC PROJECT.

A. Beginning on page 64 of her direct testimony, Ms. Jackson describes the project as an expansion and renovation of the NORC facility. She states that the current building is not sufficiently large or functional to support employee training and the construction team in the northern service area of Michigan. She further states that the limited space requires employees to travel to other areas of the Company service area to complete periodic and evolving training requirements. The total cost of the project from inception to completion is $6.1 million, with $50,000 included in 2025, $1,125,000 in the 9 months ending September 2026, and $3,750,000 for the projected test year.

Q. WHAT IS YOUR ASSESSMENT OF THE NORC PROJECT?

A. In discovery, the Attorney General asked the Company to identify the evolving training requirements and operational needs in Northen Michigan. The Attorney General also asked the Company to identify what the space constraints are and why they cannot be resolved with existing buildings and facilities in Northen Michigan and surrounding areas.

Additionally, the Company was asked to provide the cost/benefit analysis justifying the project and to identify the current phase of project development.

In response, the Company stated that new and younger employees in Northen Michigan are less experienced and need more training, plus the introduction of new and complex field equipment and technology requires more training.[43] These additional training needs are not unique to employees in Northen Michigan and also exist in other areas of the Company. The most efficient way to train employees is to make use of existing training resources and investments in training facilities that the Company already has in other areas of the state and not duplicate resources and investments in Northen Michigan. Although it may require those employees to travel outside of their service area, the cost of travel once or twice annually should not rise to the $6.1 million the Company wants to spend on a larger facility.

In response to discovery, the Company stated that it had not performed a cost/benefit analysis for the project and attempts to justify it based on operational needs.[44] Although operational needs are one aspect of the project, the CBA would show whether there is a sound economic basis to undertake the project.

Lastly, in response to discovery, the Company stated that the project is currently in the project planning and scoping phase.[45]

[43] Exhibit AG-13 includes DR AGDG-4.160a and b.
[44] Id. includes DR AGDG-4.160f.
[45] Id. includes DR AGDG-4.160e.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION FOR THE NORC PROJECT?

A. The Company has not adequately justified the capital spending of $6.1 million to expand and renovate the NORC facility. The project lacks economic justification and an evaluation of other options for use of existing training facilities that could reduce or avoid the proposed capital spending entirely. Moreover, the project is currently in the planning and scoping phase of development and premature to include in rate base in this rate case.

Therefore, I recommend that the Commission remove the forecasted capital expenditures of $1,125,000 for the 9 months ending September 2026 and the $3,750,000 for the projected test year.

Q. PLEASE DISCUSS THE MICHIGAN AVENUE SERVICE CENTER RENOVATION PROJECT.

A. Beginning on page 67 of her direct testimony, Ms. Jackson describes the project as a full renovation of the Michigan Avenue Service Center facility. She states that the current building has not been renovated since it was built in the late 1980s and some of the equipment and facilities have reached their end of life and need to be replaced. She further states that the current building is inefficient and once renovation begins it will need to meet the latest code standards. The total cost of the project from inception to completion is $5.0 million, with $200,000 included in the 9 months ending September 2026 and $4,800,000 in the projected test year.

Q. WHAT IS YOUR ASSESSMENT OF THE MICHIGAN AVENUE SERVICE CENTER RENOVATION PROJECT?

A. In discovery, the Attorney General asked the Company to identify what problems have been experienced at the service center in the past three years, such that a major or full renovation is required. In response, the Company pointed to the HVAC and plumbing and provided a list of requested repairs. The list primarily shows the need for routine maintenance and repairs that occur for a building of that age that should be addressed as they occur. It does not identify any major structural problems that justify a full renovation at this time at a cost of $5.0 million.

In response to discovery, the Company stated that it had not performed a cost/benefit analysis for the project and provided instead a facility renovation scoring methodology.[46] Although such a score card can be useful to identify improvements, a CBA would show if there is a sound economic basis to undertake the project.

Furthermore, in response to discovery, the Company stated that the project is currently in the project planning and scoping phase.[47]

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION FOR THE MICHIGAN AVENUE SERVICE CENTER RENOVATION PROJECT?

[46] Id. includes DR AGDG-4.160f.
[47] Id. includes DR AGDG-4.160e.

A. The Company has not adequately justified the capital spending of $5.0 million to expand and renovate the Michigan Avenue Service Center building. The project also lacks economic justification. Moreover, the project is currently in the planning and scoping phase of development and premature to include in rate base in this rate case.

Therefore, I recommend that the Commission remove the forecasted capital expenditures of $200,000 for the 9 months ending September 2026 and the $4,800,000 for the projected test year.

E. Gas Information Technology

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO FORECASTED CAPITAL EXPENDITURES FOR INFORMATION TECHNOLOGY.

A. In my review of the information technology (IT) projects presented by the Company in this rate case, I identified capital expenditure disallowances for the following projects: HPP Self-Service Portal, HPP Product Enhancements, ESRI Gas Utility Network Model, and MWM Enhancements project.

1. HPP IT Projects

In Exhibit A-12, Schedule B5.4.2, the Company included actual capital expenditures of $2,010,000 for 2024 for two IT projects for the Gas Appliance Service program, also referred as the Home Protection Plus (HPP) program, and forecasted capital spending of $1,862,000 for 2025, $1,313,000 for the 9 months ending September 2026, and $963,000

for the projected test year. Ms. Huffman discusses the two projects beginning on page 53 of her direct testimony.

Q. PLEASE DISCUSS THE HPP SELF-SERVICE PORTAL PROJECT.

A. According to Ms. Huffman, the HPP Self-Service Portal IT project entails the development of a digital platform to allow customers enrolled in the HPP program to review their account information, such as their enrollment date, cost of their contract, make enrollment changes, create service orders for repair service after business hours, and perform other functions. Ms. Huffman also stated that giving customers access to this information and functionality would increase the number of HPP enrollments. The project began in 2024 and will continue into 2027 at a total cost of $3.4 million.[48]

In discovery, the Attorney General asked the Company to explain why development of a new system was necessary when the customer is given a contract showing the terms of the contract and can call customer service for the infrequent occasion when appliance repair service is needed. The Attorney General also asked the Company to identify how many customers requested such digital information and access to service or repair orders during off hours. In response, the Company pointed to a survey of customers in Western Michigan indicating that certain age groups and customer segments prefer a digital

[48] DR AGDG-2.59a.

interaction. No specific data was provided by the Company showing any overwhelming demand for a self-service portal.[49]

The Company also confirmed that customers are provided with a copy of the HPP contract and terms and there are no invoices issued for completed service repairs given that repairs are completed free of charge under the subscription program. In response to the request to explain how the self-service portal would increase enrollment in the HPP program, the Company could not point to any specific data and repeated the potential appeal of digital access to information. Lastly, the Company confirmed that no CBA had been performed to economically justify the project.[50] Curiously, in the response the Company stated that the profit generated by the program justifies undertaking the self-service portal project. This statement seems to imply that, if the program generates a profit, then it can spend the money on IT projects without economic justification.

Q. PLEASE DISCUSS THE HPP ENHANCEMENTS PROJECT.

A. Ms. Huffman discusses this project beginning on page 56 of her direct testimony. She describes the project as a modification to existing plan offerings, developing the ability to update prices without IT involvement, offering plans to customers in new regions of the state, and making other process improvement changes. The project began in 2024 and will continue into 2027 at a cost of $3.0 million.

[49] Exhibit AG-15 includes DR AGDG-2.59d and f.
[50] Id. includes DRs AGDG-2.60a, BMK-6.9c, and AGDE-2.60b.

In discovery, the Attorney General asked the Company to explain the necessity to undertake this project and the need for the improvements being requested, provide the cost/benefit analysis showing the project is economically justified, and explain how these enhancements will increase customer enrollments. In response, the Company could not provide any more information on modifying existing plan offerings other than vague references to aligning customer plans to the regions where those offering are being made and allowing customers to tailor their selections.[51]

Additional discovery responses show that the ability to effectively operate the current system exists by involving the IT department when making price changes, soliciting customers in new zip code areas of the state, and supporting other functions needed by operating personnel. Access to customer information by customer service representatives also exists and the proposed modifications would increase convenience but are not essential.[52] Similar to the Self-Service Portal project, the Company did not perform a CBA and claims, without evidence, that the modifications would increase HPP customer enrollments.[53]

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE TWO HPP IT PROJECTS?

A. In summary, the Company has not made a compelling and convincing case that it is necessary to spend $6.4 million on the HPP Self-Serve Portal and Enhancement projects.

[51] Exhibit AG-16, includes DR AGDG-2.61c.
[52] Id. includes DR AGDG-2.61d, e, and f.
[53] Id. includes DR AGDG-2.62a-b.

At a time when customer gas bill affordability is a great concern, non-essential projects that increase customer costs should not be undertaken. Therefore, I recommend that the Commission disallow capital expenditures of $2,010,000 for 2024, $1,862,000 for 2025, $1,313,000 for the 9 months ending September 2026, and $963,000 for the projected test year.

2. Premature IT Projects

On line 11 of Exhibit A-12, Schedule B5.4.1, the Company shows capital expenditures for the Gas Utility Network Model of $451,000 for 2024 and forecasted capital spending of $3,286,000 for the 9 months ending September 2026 and $3,661,000 for the projected test year. Also, on line 17, the Company shows forecasted capital expenditures of $1,125,000 for the IFS Mobile Work Management (MWM) Enhancements project.

In discovery, the Attorney General asked the Company to provide the total cost of the Gas Utility Network Model from inception to completion and the current phase of project development. In response, the Company reported that the project will cost approximately $14 million between capital and O&M spending during development, lasting through the year 2029. In addition, the Company stated that the project is currently in the planning phase.[54]

Regarding the MWM Enhancements project, in response to discovery, the Company stated that this project is the second phase of a previous MWM project that will add other

[54] Exhibit AG-17 includes DR AGDG-6.261a-b.

functionality. The Company also reported that the Enhancement project is scheduled to begin in 2027.[55]

Both of these projects are still in the early stages of project development with costs and timelines not yet firmly established. The timing and amount of capital expenditures is still preliminary and uncertain. It is premature to include the proposed capital expenditures in rate base in this rate case.

Therefore, I recommend that the Commission remove the combined capital expenditures of $451,000 for 2024, $3,286,000 for the 9 months ending September 2026, and $4,786,000 for the projected test year.

F. Capital Expenditures Adjustments - Summary

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING THE TOTAL AMOUNT OF ADJUSTMENTS TO THE COMPANY'S CAPITAL EXPENDITURES AND RATE BASE?

A. The chart below summarizes my proposed reductions in capital expenditures in those areas where the level of capital expenditures presented by the Company is excessive, unnecessary, or unsupported.

[55] Id. includes DR AGDG-6.267b-c.

Summary of AG Disallowed Capital Expenditures		
		Amount (millions)
Distribution Plant		
Main Renewals		9.5
Public Improvements		6.4
Service Alterations		9.6
Communications & Controls - Meters		9.9
Customer Attachments		33.3
System Reliability		3.8
IRM 2015 Disallowance		18.4
Transmission Plant		
South Grand Rapids Pipeline		27.8
East Petoskey Pipeline		35.8
Gas Storage & Compression		
Columbus 23 Upgrade		2.3
Belle River Mills Z5 Engine		6.1
Belle River MillsTurbine Engine		6.0
General Facilities		
Northen Operations Resource Center		4.9
Michigan Ave. Service Center		5.0
Iinformation Technology		14.7
Total	**$**	**193.5**

Based on my analysis and information presented in my testimony above, the Commission should reduce the Company's proposed capital expenditures by $193.5 million and average rate base by $157.5 million, including an $18.0 million reduction in working capital. Exhibit AG-18 provides additional details and calculations of these amounts.

V. Working Capital

Q. ON EXHIBIT A-12, SCHEDULE B4, THE COMPANY PROPOSES A WORKING CAPITAL AMOUNT OF $837.2 MILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY'S FORECASTED AMOUNT?

A. No. I propose two adjustments, which decrease the amount of working capital by $18.0 million. The first adjustment pertains to Taxes Payable. The second adjustment is related to the Company's calculation of prepayments (prepaid taxes) for the projected test year.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO TAXES PAYABLE OF $12.2 MILLION.

A. The Company's projected test year balance of minus $2.7 million for Taxes Payable is $12.2 million lower than the actual historical 2024 balance of $9.5 million. Taxes Payable as determined by the Company are shown on line 79 of page 2 of Exhibit A-12, Schedule B4.2.

In discovery, the Attorney General asked the Company to explain why Taxes Payable would decrease when the rate relief requested in this rate case would increase taxable income. In its response, the Company stated that for calculation of Taxes Payable in this rate case, it forecasted a taxable loss for the 2027 test year, and that for this calculation, no rate relief was included for purposes of income tax expense and income taxes payable for

the projected test year.[56] The Company calculated its Federal, State, and Local income tax expense on Exhibit A-13, Schedules C8, C9, and C10. A review of these schedules shows that the Company has included all the higher expenses proposed in the projected test year in this rate case above the 2024 historical year and no additional revenue from the rate relief requested.

The inclusion of all higher expenses and the exclusion of any new rate relief from this case, which results in a tax loss, is not realistic. Therefore, the Company's calculation of negative Taxes Payable is seriously flawed and incorrect. Although an assumption could be made that the Company will receive some increase in revenue from this rate case, a more conservative approach would be to at least use the actual Taxes Payable balance from the 2024 historical period. Accordingly, I recommend that the Commission utilize the historical balance of Taxes Payable of $9.5 million as a reasonable proxy for the projected test year.[57]

This increase in Taxes Payable of $12.2 million for the projected test year reduces working capital by the same amount.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE COMPANY'S PREPAYMENTS OF PROPERTY TAXES.

[56] DR AGDG-1.17(a) and (b).
[57] Line 79, page 2 of Exhibit A-12, Schedule B4.2.

A. As shown on line 30 of page 2 Exhibit A-12, Schedule B4.2, the property taxes prepayments average balance increases from $32.8 million in the historical year to $46.8 million in the projected test year. In response to two different discovery requests submitted by the Attorney General requesting additional information on the $14 million increase, the Company either would not or could not provide clear and sufficient justification for the large increase.[58]

In response to one of the discovery responses, the Company showed that the average balance for Prepayments increased from $23.8 million in 2020 to $32.8 million in 2024, which reflects an annualized increase of 8.4%. Using this rate of increase over the 33-month period between the historic test year and the projected test year, the total increase in the prepaid property taxes balance would be $8.2 million instead of the $14.0 million forecasted by the Company. Exhibit AG-19 shows the calculations.

The Company's forecasted increase in Prepayments is excessive and unjustified. Therefore, I recommend that the Commission reduce the Company's forecasted prepayments for property taxes for projected test year and working capital by $5.8 million ($14 million – $8.2 million).

In total for Taxes Payable and Prepayments, I recommend that the Commission reduce the projected test year working capital by $18.0 million, as reflected on Exhibit AG-19.

[58] Exhibit AG-20 includes DR AGDG-1.14 and 5.214a-c.

VI. Cost of Capital and Capital Structure

A. Capital Structure

Q. **WHAT IS THE CAPITAL STRUCTURE YOU RECOMMEND FOR USE IN THE OVERALL RATE OF RETURN CALCULATION?**

A. I recommend that the capital structure shown on page 1 of Exhibit AG-21 be used in this case. The first three lines show the projected long-term debt, preferred equity, and common equity capital of the Company, which represents the permanent capital structure for the test period ending September 2027. The capital balances in this exhibit reflect the amounts shown in Company Exhibit A-14, Schedule D1, with an adjustment to rebalance the capital structure. The long-term debt component in Exhibit AG-19 has been increased by $49.2 million and the common equity component has been reduced by the same amount. The result is a capital structure with 50% of common equity and 50% of long-term debt.

Q. **WHY DID YOU INCREASE LONG TERM DEBT BY $49.2 MILLION AND OFFSET THIS CHANGE WITH A LOWER COMMON EQUITY BALANCE?**

A. The Company proposed a permanent capital structure with a common equity component of 50.75%. This level of common equity exceeds the 50% equity ratio approved by the

Commission in the Company's last fully contested gas rate case, Case No. U-21291, and other recent rate cases for Consumers Energy Company and DTE Electric Company.[59]

The Company's financial circumstances and risk profile have not changed to any significant degree since the Commission order in Case No. U-21291 to warrant a common equity ratio above 50%. In addition, the Commission's consistent directives in recent electric and gas rate cases have concluded that a 50/50 capital structure is desirable and appropriate to ensure reduced costs to customers while still maintaining the utilities' strong financial position. Other relevant factors that support a 50/50 capital structure include; (1) The Company's strong cash flow to debt coverage ratio and credit ratings; (2) the Company's common equity capital contributions by the parent company; (3) the favorable regulatory environment in Michigan supported by historical returns on common equity above industry averages and in the top tier of the Company's peer group; and (4) the fact that the common equity ratio of the peer group, used to assess the cost of common equity in this case, is approximately 47%.[60]

Q. PLEASE DISCUSS FURTHER THE COMMISSION'S CONCLUSIONS AND DIRECTIVES IN ESTABLISHING A 50% EQUITY RATIO FOR DTE GAS, CONSUMERS ENERGY, AND DTE ELECTRIC.

[59] MPSC Case No. U-21291 Commission order dated November 7, 2024. MPSC Case Nos. U-21860. U-21534, U-21297, U-21806, and U-21585.
[60] Exhibit AG-24 shows that the equity ratio for each peer company and the peer group average ratio of 46.8%.

A. In the last DTE Gas rate case, No. U-21291, the Commission stated:

> The Commission finds that the record supports the ALJ's recommendation to adopt a capital structure of 50% equity and 50% debt. The Commission is unconvinced that the adoption of a 50/50 capital structure will degrade the Company's credit metrics. See Tr 1615 – 1617. Further contrary to the Company's assertion, this does in fact reflect a gradual reduction in the authorized equity layer, consistent with Commission precedent.[61]

In the March 21, 2025, order in the Consumers Energy electric rate case No. U-21585, the Commission decided to set the common equity ratio at 50%, as recommended by the Administrative Law Judge (ALJ) and supported by the Attorney General and other parties. On page 129 of the order, the Commission stated:

> Given the above, the Commission adopts the thorough and well-reasoned findings and recommendations of the ALJ. The Commission finds that the balanced capital structure most appropriately balances the interests of the utility's investors and customers, consistent with the holdings in Bluefield and Hope. As such, the Commission adopts a balanced capital structure of 50% debt to 50% equity, utilizing the Attorney General's methodology.

Similarly, in the September 30, 2025 order in the Consumers Energy gas rate case No. U-21806, the Commission stated:

> Given the above, the Commission finds that Consumers' exceptions are not persuasive and do not support the Company's requested equity layer. The Commission agrees with the ALJ's substantive and thorough evaluation of the evidence and concludes that the record evidence warrants a continuation of the 50/50 balance between debt and equity. Therefore, the Commission adopts the ALJ's findings and recommendation with respect to the proposed capital structure.[62]

Most recently, in the DTE Electric rate case No. U-21860, the Commission stated:

> Having reviewed the record and the parties' arguments on the issue, the Commission finds the ALJ's recommendation to maintain a balanced capital structure comprised of 50% debt and 50% equity to be well reasoned and supported by the record.

[61] MPSC Case No. U-21291 order dated November 7, 2024 at page 93.
[62] MPSC Case No. U-21806 order dated September 32, 2025 at page 162.

Accordingly, the Commission adopts the ALJ's findings and conclusions on this issue.[63]

The Commission has been very clear that a balanced permanent capital structure at 50% debt and 50% equity capital is appropriate for Michigan utilities.

Q. PLEASE DISCUSS THE COMPANY'S CREDIT METRICS FOR THE CASH FLOW TO DEBT RATIO?

A The most recent Moody's report of July 2025 shows the Company's operating cash flow to debt coverage (CFO Pre-W/C to Debt) ratio at 18.7% for 2024 and 24.7% for 2023.[64]

The decline in the coverage ratios from 24.7% in 2023 to 18.7% in 2024 reflects a short-term change in the Company's earnings and returns from 11.5% in 2023 to 9.1% in 2024, reflecting the impacts of warmer weather and other factors.[65]

Q. DID YOU CALCULATE THE IMPACT ON THE MOODY'S CASH FLOW TO DEBT COVERAGE RATIO BASED ON A 50% EQUITY RATIO IN THE COMPANY'S CAPITAL STRUCTURE AND AN AUTHORIZED ROE OF 9.80%?

A. Yes. On page 1 of Exhibit AG-29, I calculated the Company's CFO to debt coverage ratio for 2024 adjusted for the ROE and common equity ratio levels I advocate in this case. I start with Moody's actual results for the 2024 period and adjust them to reflect a 9.80%

[63] MPSC Case No. U-21860 order dated February 19, 2026 at page 276.
[64] Exhibit AG-31 includes U-21973 JEU 1.1, Att. 2 with the Moody's credit report dated July 17, 2025.
[65] See Exhibit A1, Schedule A2, page1, line 11. Also, page 9 of DTE Energy's 2024 Year-end Earnings Conference Call dated February 13, 2025.

ROE and a 50% common equity ratio. I chose this 2024 period because this is the most recent annual information available from Moody's showing detailed ratio components.

For my analysis of the 2024 pro-forma cash flow ratio calculation, I started with actual 2024 data (per the Moody's July 2025 report) on line 1 of Exhibit AG-29. Next, on line 2, I adjust the capitalization to reflect a balanced capital structure. This increases long-term debt and decreases common equity. On line 3, I adjusted the cash flow upward to reflect a 9.80% ROE versus the 9.10% ROE actually achieved in the year ended December 2024. The result of these adjustments is shown on line 4 with a cash flow to debt ratio of 18.9%. This ratio is well above the 16% downgrade threshold noted by Moody's in its July 2025 report.[66] I have not presented any ratio results for S&P since the ratio calculations are highly similar, and the S&P downgrade threshold is lower at 11%.[67]

In summary, my analysis shows that the 9.80% ROE and 50% common equity ratio would result in the Company's cash flow ratios being above the long-term threshold levels that would result in a credit downgrade.

Q. DO THE RATING AGENCIES' CURRENT BUSINESS AND CREDIT OUTLOOK FOR THE COMPANY SHOW ANY SIGNIFICANT CONCERNS?

A. No. In its October 2025 report, S&P provides the following outlook for the Company:

[66] Exhibit AG-32 includes the Moody's July 17, 2025, report. See DR 21973 JEU-1.1, Att. 2 showing the 16% downgrade threshold.
[67] Exhibit AG-31 includes U-21973 Staff Audit Request JEU 1.1 Att. 1, S&P October 2, 2025 report on page 2 under Downside Scenario.

> The stable rating outlook on DTEG reflects our base case assumption that it will generate sufficient cash flow to maintain appropriate financial measures for their current rating including stand-alone FFO to debt of 17% to 19% from 2025 to 2027. The outlook also reflects our expectation that DTE Energy Company's management will remain focused on its core utility operations and maintain the Company's current credit measures.[68]

Similarly, in its July 17, 2025 report, Moody's provides the following rating outlook:

> The stable outlook reflects our expectation that the Michigan legislative and regulatory environment will remain credit supportive and enable DTE Gas to recover prudently incurred capital investments on a timely basis. Also, the stable outlook incorporates our expectation that DTE Gas will continue to produce consistent and predictable financial metrics.[69]

Fitch Investor Service provided the following summary of the Company's credit profile in its March 28, 2025, report:

> Constructive Regulatory Environment: Fitch views the regulatory environment for natural gas utilities in Michigan as constructive. The regulatory framework allows full pass-through of fuel costs, forward-looking test years and a timely resolution of rate proceedings. DTE Gas's authorized return on equity (ROE) of 9.8% is slightly higher than the 2024 industry average of 9.72%.[70]

These credit reports provide a favorable outlook of the Company's credit profile and Michigan's regulatory environment. Mr. Lepczyk did not provide any evidence to contradict those favorable outlooks. In fact, in discovery, the Attorney General asked if any of the credit rating agencies had notified the Company regarding the need for a higher equity ratio. In response, Mr. Lepczyk stated that no such notifications had been received.[71]

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[68] Exhibit AG-31 includes DR 21973 JEU-1.1 with related attachment.
[69] Id.
[70] Id. includes DR 21973 JEU 1.1, Att. 3
[71] Exhibit AG-33 includes DR AGDG-1.9a.

Q. PLEASE DISCUSS THE FAVORABLE REGULATORY ENVIRONMENT IN MICHIGAN.

A. The Company benefits from several legislative and regulatory mechanisms that have resulted in stable earnings, above average returns for shareholders, and lower risks for creditors. These mechanisms include (a) the use of fully projected test years to recover costs matched to forecasted operations and expenditures, (b) a 10-month mandated period for rate case decisions and the ability to file annual rate cases, (c) full cost and timely recovery of gas costs, (d) a revenue decoupling mechanism to recover lost revenues from customer energy conservation, and (c) regulatory asset mechanisms for deferred recovery of costs.

On page 2 of its most recent credit report under the section Rating Outlook, Moody's stated "The stable outlook reflects our expectations that the Michigan legislative and regulatory environment will remain credit supportive…." Similarly on page 4 of the latest credit report under the section Business Risk, S&P points to the Company's "constructive regulation" and "effective regulatory risk management".[72] These reports were issued after the Commission approved the 50% equity ratio for the Company in Case No. U-21291.

[72] Exhibit AG-31 includes JEU-1.1 attachments 1 and 2.

Therefore, there should be no concern that rating agencies will be surprised by any perceived regulatory policy changes with the Commission re-approving a 50% equity ratio in this rate case.

Q. **YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP USED TO ASSESS THE COST OF COMMON EQUITY IS APPROXIMATELY 47%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE COMMON EQUITY RATIO FOR THE COMPANY.**

A. As shown in Exhibit AG-24, the average common equity ratio of the peer company group was 46.8% for the four quarters ended September 2025. The cost of equity for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure. Thus, it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible, in order to have consistency with the cost of equity capital derived from those peer group companies. The Company's proposed common equity capital ratio of 50.75% creates a disconnect that is not acceptable and is also more costly to customers.

Q. DOES THE COMPANY MAKE A COMPELLING CASE TO SUPPORT ITS PROPOSED 50.75% COMMON EQUITY RATIO FOR THE PERMANENT CAPITAL STRUCTURE?

A. No. Company witness Timonthy Lepczyk addresses the proposed capital structure on pages 6 to 15 of his direct testimony. In addition to a general discussion about the objective

of maintaining a strong balance sheet and credit ratings, Mr. Lepczyk raises the following items: (1) the higher equity ratios of peer gas distribution companies; (2) DTE Gas being a smaller utility in comparison to DTE Electric and Consumers Energy; (3) the Company's capital structure being "balanced" if short-term debt is taken into consideration; and (4) the ability of DTE Gas to attract capital. I will address each of these items.

First, Mr. Lepczyk states that his peer group of utility companies has an average equity ratio of 54.28%. He references Exhibit A-17, Schedule G-3, with information sourced from S&P Global. The debt and equity balances used in the calculation of the 54.28% equity ratio in the exhibit are at a single point in time at the end of 2023 or 2024, depending on the year he selected. There are several problems with the information in the exhibit that make it unreliable and inapplicable in setting an appropriate equity ratio for the Company. To begin with, utility equity balances change during the year due to seasonality in sales and net income or net losses, which add or reduce the monthly or quarter-end balances. The timing of retirement and issuance of long-term debt and temporary financing with short-term debt also affects the long-term debt balances and the equity ratio as a percentage of the total permanent capital. An appropriate calculation of equity and debt balances and resulting equity ratio needs to be done over multiple, quarter-ended balances.

Additionally, the list of utility subsidiaries in the peer group includes several small size utilities that are not comparable to DTE Gas. This is apparent when comparing the total permanent capital of most of the subsidiaries of NiSource and One Gas in Exhibit A-17,

Schedule G3, to the total permanent capitalization of DTE Gas of $5.8 billion. Some of these smaller utilities have a permanent capitalization that is less than 10% of Company. Smaller utilities tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage.[73] This is not the case with DTE Gas.

Second, Mr. Lepczyk's position that DTE Gas is a small gas utility in comparison to the two large electric utilities in Michigan and somehow should be given deference from a 50% equity ratio is unconvincing. Compared to larger *electric* utilities, DTE Gas is somewhat smaller, but this is the case for most natural gas distribution companies in combination gas and electric utility companies. DTE Gas, with revenues of $1.3 billion and a rate base of $8.0 billion, is generally comparable to the gas business of Consumers Energy, which has revenues of $2.1 billion and a rate base of $10.0 billion.[74] In Case No. U-21806, the Commission approved an equity ratio of 50% for the gas business of Consumers Energy. Therefore, there is no basis here for Mr. Lepczyk to draw a significant distinction that would justify a higher equity ratio for DTE Gas.

Third, Mr. Lepczyk states that the rating agencies consider short-term debt as a component of total debt in their debt ratios and cash flow to debt coverage. Mr. Lepczyk's argument is that when short-term debt is added to the permanent capital of the Company the resulting

[73] In particular, the Atmos rate base for its investments in Colorado, Kansas, Kentucky, and Tennessee ranges from $300 million to $900 million (approximately 10% or less than DTE Gas) according to the Atmos 2024 form 10-K (page 7). Also, as can be seen on Exhibit A-17, Schedule G4 NiSource includes 3 units with capital of $1.25 billion or less and OneGas contains 3 units at $2.2 billion or capital or less.
[74] Case U-21981, Exhibit A1, Schedules A-1 and A-2.

math shows that DTE Gas has a balanced capital structure. This faulty argument is not new. Consumers Energy has raised the same argument before in some of its rate cases and the Commission has rejected it.[75] Also, the analysis I prepared on the cash flow to debt ratio starts with the rating agency data, which includes short-term debt. Therefore, the results of my analysis take into account the Company's short-term debt.

Fourth, Mr. Lepczyk speculates that a capital structure with an equity ratio less than 50.75% may impact the Company's ability to attract capital to fund capital expenditures. This appears to be DTE looking for a "problem" to justify its desired capital structure. The Company has not had any problems raising debt capital through the financial market or equity capital from its parent company since the Commission approved an equity ratio of 50% in Case U-21291.[76] No evidence has been presented supporting Mr. Lepczyk's concern. In fact, during the past three years, the Company has raised $1.5 billion in debt capital at competitive interest rates with $260 million raised since the February 2025 Commission order in Case U-21291.[77]

In summary, Mr. Lepczyk has not provided any compelling or convincing evidence that the Company's equity ratio should be increased from 50% to 50.75%. Therefore, I recommend that the Commission reject the proposed 50.75% equity ratio and maintain a

[75] In the December 22, 2021 order in Case No. U-20963 at page 201, the Commission addressed Consumers Energy's argument and what constitutes a balanced capital structure and dismissed the inclusion of short-term debt to the permanent capital structure.
[76] DR AGDG-7.303.
[77] Exhibit A-14, Schedule D2, lines 25 to 30.

balanced permanent capital structure of 50% long-term debt and 50% equity capital for the Company.

Q. WHAT IS THE REVENUE REQUIREMENT SAVINGS RELATED TO A LOWER COMMON EQUITY RATIO OF 50.0% IN COMPARISON TO THE COMPANY'S PROPOSED EQUITY RATIO OF 50.75%?

A. The difference is approximately $4.6 million annually. This reflects (a) the difference between the pre-tax cost of common equity of approximately 13.9% versus the cost of long-term debt of 4.6%; (b) the Company's proposed rate base of approximately $8.0 billion; and (c) the percentage of total capital being shifted from common equity to long term debt.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE OTHER ITEMS INCLUDED IN THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. No. For the other components of the capital structure, I adopted the balances sponsored by witness Vangilder in Exhibit A-14, Schedule D1, page 1.

COST OF CAPITAL

Q. **WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL ARE YOU RECOMMENDING IN THIS CASE?**

A. I recommend an overall return on capital of 5.93%, which includes a return on common equity of 9.80%, as shown in Exhibit AG-21, page 1.

Q. WHAT COST RATE DID YOU UTILIZE FOR LONG TERM DEBT?

A. For the long-term debt cost rate, I used a rate of 4.59% based upon Exhibit AG-21, page 2. My 4.59% cost rate is slightly lower than the 4.65% rate determined by witness Lepczyk on Exhibit A-14, Schedule D2 at line 30. Mr. Lepczyk included the new debt cost related to the Company's planned September 2027 debt issue as if it were outstanding during the entire projected test year. Page 2 of Exhibit AG-21 shows the proper inclusion of the Company's September 2027 debt issuance for only one-twelfth of the projected test year (not the full year), which results in a lower long-term debt rate. In response to discovery, the Company stated that the Company had used this incorrect approach in prior rate cases.[78] However, the fact that this incorrect approach was not detected in those cases does not justify continuing it.

Q. WHAT COST RATE DID YOU UTILIZE FOR SHORT TERM DEBT AND THE OTHER COMPONENTS OF THE CAPITAL STRUCTURE?

A. For Deferred Taxes, I used a zero-cost rate recommended by witness Vangilder. Cost rates for JDITC reflect those rates I used for the permanent capital sources. For short-term debt, I used the 5.06% rate proposed by Mr. Lepczyk in Exhibit A-14, Schedule D3.

[78] DR AGDG-1.7d.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-21.

A. To arrive at the overall cost of capital on line 12, column (f), I first developed the percentage weighting of each capital component in column (d) by dividing the individual capital balances in column (b) by the total of all capital components in that column. Next, I multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the values in column (f). The total of the individual values in column (f) is the total cost of capital of 5.93%.

Regarding the pretax weighted cost of capital on line 12, column (h), I have multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income and other taxes paid by the Company for calculation of the pretax weighted cost of 7.35% in column (h).

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN DETERMINING THE COST OF COMMON EQUITY FOR THE COMPANY?

A. 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. In its opinion in Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia (the "Bluefield Case") 262 U.S. 679 (1923), the United States Supreme Court indicated that:

> 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 being made at the same time…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….

The principals of the Bluefield Case were re-affirmed by the U.S. Supreme Court in 1944 in the case FPC v Hope Natural Gas Company, 320 U.S. 591.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON EQUITY IN EXHIBIT AG-22.

A. Determining the cost of common equity for an enterprise or an industry group is inexact since investors can only estimate what the future cash flow from any enterprise may be over time. Because of this uncertainty, most financial experts will not rely solely on any particular method. To determine the cost of common equity, I used three approaches to assess this cost. These are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and the Utility Risk Premium approach.

Q. **PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROXY GROUP OF PEER COMPANIES.**

A. To develop an appropriate peer group, I started with six of the nine utility companies followed by the Value Line Investment Survey in its "Natural Gas Utility Industry" section

and have added a seventh company, which is WEC Energy Group.[79] The three natural gas companies followed by Value Line that I eliminated are Spire (due to M&A activity), UGI (due to its large propane and foreign operations), and Southwest Gas. Regarding this latter Company, its finances have been adversely impacted by a reorganization spurred by investor and corporate raider Carl Icahn. Southwest reported a return on equity capital of approximately 6% in 2023 and 2024. As a result, Value Line forecasts that the earnings per share (EPS) of Southwest Gas will double by 2029 from the low 2024 earnings base.[80] This large increase in EPS is not representative of the company's long-term growth in earnings. For these reasons I have excluded Southwest Gas from the peer group.

As mentioned above, I have added WEC Energy Group to my peer group. Forty percent (40%) of this Company's revenues and 48% of its customers are in the natural gas business.[81] Its natural gas subsidiaries include Michigan Gas Utilities, Peoples Gas in Chicago, North Shore Gas in northern Illinois, and Wisconsin Gas.

Q. HOW DOES YOUR PEER GROUP COMPARE TO THE COMPANY'S PEER GROUP?

A. My peer group includes five of the six companies in the Company's peer group. These are Atmos, New Jersey Resources, NiSource, Northwest Natural Gas Holdings, and One

[79] In prior rate cases, the Attorney General included Black Hills as a proxy company due to its significant gas distribution business. However, Black Hills is now involved in a merger with NorthWestern, which makes it a poor peer group candidate at this time.
[80] Corporate non-utility losses of $63 million in 2024 and $77 million in 2023 due to Mountain West Pipeline Goodwill impairment ($50 million) and expenses for separation of Centuri Construction.
[81] WEC Energy Group 2024 Form 10-K at page 19 (revenues) and pages 5 and 11 (customers).

Gas. The Company included Southwest Gas in its peer group, which I excluded due to the residual problems stemming from this company's reorganization and its depressed earnings discussed above. The Company did not include Chesapeake Utilities and WEC Energy in its peer group, which are in my peer group.

Discounted Cash Flow (DCF) Cost of Equity Method

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") APPROACH.

A. The DCF approach is based on the proposition that the price of any security reflects the present value of all future cash flows (dividend flows) from the security discounted at a single discount rate which, in the case of common stocks, is the required return on equity. Expressed mathematically, the resulting equation can be reconfigured to solve for the required rate of return, and this equation is:

$$R = D/P + g$$

where "R" = the Required Equity Return
"D/P" = the Dividend Yield on the Security
and "g" = the expected growth rate in dividends

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-23. The stock price information in column (c) of this exhibit reflects the average of the high and low prices for each of these equity securities on each of the thirty trading days from November 18 to December 31, 2025. The annual dividend in column (d) is the forecasted average dividend

level for 2026 as projected by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on (1) the estimate of earnings growth through 2029 per Value Line; and (2) S&P Capital IQ. For Chesapeake Utilities and NiSource, I excluded the Value Line earnings growth estimates because they were 8% or higher. Growth rates of 8% and higher are an aberration and not representative of long-term growth for gas utilities that have average annual customer growth rates of 1% or less.

The resulting calculation of the DCF Method is an average return on common equity for the proxy group of 9.96%.

Q. PLEASE ASSESS THE RESULTS OF THE DCF ANALYSIS YOU PERFORMED.

A. The DCF analysis relies upon financial market information for the dividend yield portion of the equation. It also relies upon judgments of dividend and earnings growth prospects of security analysts, which reflects the consensus of the market on which investors rely. Therefore, I place a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other methods in determining the cost of common equity.

Q. HOW DOES YOUR DCF COST OF CAPITAL ESTIMATE COMPARE TO THE COMPANY'S DCF ESTIMATE?

A. First, I will point out that Company witness Nelson has calculated several DCF outcomes based on stock price averages over 30 days, 90 days, and 180 days, as well as multiple quarterly dividend growth approaches. My comparison below is against the Company's

"30-day average" stock price approach without any quarterly compounding of dividends. The results of my DCF analysis and those of witness Nelson are dependent in large part upon the overall dividend yield in each case as well as the average growth rate of each peer sample. Witness Nelson's average DCF result of 10.78% is 82 basis points higher than the 9.96% overall DCF result I calculated.[82]

The average dividend yield in my analysis is 3.22% versus the Company's higher average of 3.49%. This accounts for approximately 33% of the 82 basis points of difference. Also, the projected growth rate is higher in the Company's case at 7.29% vs. 6.74% in my analysis.[83] With respect to my lower dividend yield, the stock prices of the utilities in the peer group were higher at the time I performed my analysis, thereby resulting in a lower dividend yield compared to the Company's filed case. Regarding the higher growth rate in the Company's DCF analysis, the 10.25% average earnings growth rate for Southwest Gas used by Ms. Nelson is nearly 300 basis points higher than the 7.29% average growth rate of her entire peer group. Excluding the aberrant Southwest Gas growth rate, the Company average would be 6.70%, which is slightly lower than my growth rate of 6.74%.

[82] This Company's 10.78% average DCF ROE rate is shown on page 1 of Exhibit A-14 (Schedule D5.2) in column 10 as the third from last number.
[83] The 3.49% dividend yield and 7.29% growth rate of the Company's peer group analysis is from columns 4 and 8 on Exhibit A-14 (Schedule D5.2).

Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL (CAPM) APPROACH TO DETERMINING THE COST OF COMMON EQUITY CAPITAL.

A. The Capital Asset Pricing Model (CAPM) is based on the proposition that the expected return on a common equity security is a function of risk as measured by the "Beta" of that security. In equation form, CAPM is as follows:

$$k_e = R_f + (B \times R_p)$$

where k_e = *The market cost of common equity for a specific security*

R_f = *the "risk free" rate of return*

R_p = *the overall return of the market less the risk-free rate (over several years)*

B = *the systematic risk of a particular common equity security vs. the market*

Q. PLEASE EXPLAIN THE BETA OR "*B*" COMPONENT OF THE EQUATION.

A. This measure of risk reflects the extent to which the price of a particular security varies in relationship to the movement of the overall market. Securities that vary over time more than the overall market will have a Beta that is greater than 1.00. Some securities vary less in price over time than the overall market. In these cases, the Beta will be less than 1.00. Utility stocks tend to move less than the overall market. Reflective of this outcome, the average Beta of my peer group is 0.74.

Q. PLEASE EXPLAIN EXHIBIT AG-24 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-24 shows the results of the CAPM method based upon (1) a 4.35% risk-free rate; (2) the Betas of the companies in the Peer Group taken from Value Line; and (3) the 7.45% historical Market Risk Premium (R_P) return from the years 1926 to 2024.

Regarding the use of a risk-free rate for CAPM purposes, I used a 4.35% rate, which is sourced from economic projections provided by the Company.[84]

The result of my CAPM approach using the 5.53% adjusted risk premium (7.45% Risk Premium x 0.74 Beta) plus the 4.35% risk-free rate is a cost of equity capital of 9.88% for my proxy group average.

Q. PLEASE ASSESS THE CAPM APPROACH.

A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios of stocks. As such, it can be useful. However, the key issue with CAPM is that it assumes that the entire risk of a stock can be measured by the "Beta" component. As such, the only risk to the investor is from fluctuations in the overall market. Practically, investors take into consideration company-specific factors in assessing the risk of each particular security. Therefore, I give the CAPM approach less weight than the DCF approach in determining the cost of common equity.

[84] Exhibit AG-34 includes witness Nelson's workpaper 24 (page 16) showing 30-year U.S. Treasury bond rates for 2027 and beyond of 4.40% and 4.30% for a 4.35% average rate.

Utility Risk Premium Approach

Q. PLEASE EXPLAIN THE UTILITY RISK PREMIUM APPROACH OF ESTIMATING THE COST OF COMMON EQUITY.

A. In general, the cost of common equity for a peer group of utility companies can be estimated by (1) projecting the cost of debt for the Company and adding to this cost (2) the average return differential of utility common stocks over utility bonds.

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-25 shows the components required to derive a cost of common equity capital for the peer companies on lines 3 and 4. The 5.54% on line 3 is the projected average rate for utility "A" rated bonds. This rate is determined from the 4.35% U.S. Treasury rate discussed earlier, plus the average spread of 30-year "A" rated utility bonds in 2024 compared to 30-year U.S. Treasury bonds. The spread rate of 3.86% on line 4 of the exhibit is the historical rate of utility returns versus "A" rated debt yields from 1955 to 2024. The total of the two rates equals the Risk Premium return rate of 9.40% on line 5 of the exhibit.

Q. DOES THE COMPANY PROVIDE A UTILITY RISK PREMIUM ANALYSIS?

A. No, not in the traditional sense of measuring stock market achieved returns on utility stocks relative to an interest rate benchmark such as utility bonds. Instead, Company witness Nelson uses an unorthodox approach that does not reflect investor returns, which she refers to as a Risk Premium method or Bond Yield Plus Risk Premium (BYRP) method.

Q. PLEASE SUMMARIZE WITNESS NELSON'S TESTIMONY ON PAGES 37 THROUGH 42 STARTING UNDER THE HEADING "RISK PREMIUM APPROACH."

A. Witness Nelson states in her testimony that she compared authorized ROEs from gas utility rate case decisions from 1980 to 2025 and compared the authorized ROEs to 30-year U.S. bond yields. She ran a regression model with this data and claims to have found a strong relationship between these bond yields and authorized ROEs. Based on her results she concludes that the average risk premium over the 1980-2025 period is 5.63%. To this risk premium, she adds a projected 30-year U.S. bond yield of 4.53% for the projected test year to arrive at a 10.15% ROE rate for the projected test year under this unorthodox approach. The calculation is shown on page 40 of her testimony.

Q. WHAT IS YOUR ASSESSMENT OF THIS APPROACH TO CALCULATING THE RISK PREMIUM COST OF EQUITY CAPITAL PRESENTED BY MS. NELSON?

A. There are three major flaws with Ms. Nelson's Risk Premium methodology. First, it lacks any comparison of actual investor returns achieved from price appreciation, dividends, and interest from stocks and bonds. It is the actual return on utility common equities that is the key and necessary measurement in any risk premium analysis. Using authorized ROEs as a substitute ignores investors' return expectations. Second, the analysis is biased because it covers a period when interest rates declined from 12.1% in late 1980 to between 4% to 5% in 2025.

Third, this analysis assumes a direct relationship between declining interest rates and ROE decisions as happening almost instantaneously on a monthly basis. Regulators approach the serious business of establishing ROEs based on many factors including the concept of gradualism in reducing or increasing ROEs that are not in lock step with interest rate changes. As such, this analysis has no validity as a tool to determine an appropriate ROE rate in rate case proceedings, and the Commission should disregard.

This methodology has no widespread acceptance among regulatory commissions. In response to discovery, the Company opines that there is some acceptance of this method by regulators in Virginia, North Carolina, and Texas. However, the extent to which it is relied on is unclear.[85]

Q. HOW DO YOUR CAPM AND MARKET RISK PREMIUM RESULTS COMPARE TO THE RESULTS PRESENTED BY COMPANY WITNESS NELSON?

A. Before engaging in comparisons of these two methods, it is important to point out that witness Nelson has calculated eight different CAPM results, eight different ECAPM results, and two different Bond Yield Plus Risk Premium (BYRP) results, all of which are shown in Exhibit A-14, Schedule D5.5 (pages 1 to 4) and Schedule D5.6. This conglomeration of multiple scenarios is confusing and does not yield any more accurate results than the three methodologies I have employed and most of the other cost of capital experts use in rate case proceedings before the Commission.

[85] DR AGDG 1.11a.

Ms. Nelson also uses different risk-free rates of return, apparently unsure which rate is most appropriate. For example, for the CAPM methodology one half of the calculations utilize the actual 4.88% 30-year U.S. Treasury Bond rate reported for 2025 at the time she prepared her analysis for this rate case. The other half of the CAPM calculation reflects a projected 30-year Treasury Bond rate of 4.53%. She also uses these two 30-year U.S. Treasury Bond rates in calculating her market risk premium results.

Another compounding effect is Ms. Nelson's use of both an historical Market Risk Premium (MRP) and a projected MRP in the calculation of the CAPM and ECAPM methodologies. In one scenario, she proposes the use of an adjusted historical MRP of 7.65%, which she calculates by subtracting the 30-year U.S. Treasury rate of 4.53% from the historical return of the stock market of 12.17% from 1926 to 2024. In other scenarios, she proposes projected MRP factors of 9.96% and 10.32%, which are around 200 to 300 basis points higher than the historical MRP, based upon projected growth rates from S&P 500 companies. I will discuss the flaws of this projected MRP factor later in my testimony due to the short-term outlook and other flaws.

My CAPM calculations reflect only the historical MRP and the projected risk-free rate. I used the historical MRP rate because it is the most reliable proxy rate of the market risk premium that spans multiple stock cycles, both up and down cycles, in the stock market over a long period of time. I use the projected risk-free rate since we are dealing with a projected test year in this rate case and it more reliably reflects the trend in interest rates over the next 18 months. Also, I present no ECAPM calculations since this methodology is flawed, as explained later in my testimony.

Q. PLEASE EXPLAIN THE DIFFERENCE IN THE MARKET RISK PREMIUMS USED BY THE COMPANY.

A. While not addressed in her testimony, it is clear from page 3 of Exhibit A-14, Schedule D5.5, that witness Nelson uses a 7.29% MRP associated with the risk-free rate of 4.88% from 2025. In the lower half of the same page, she increases the MRP to 7.65% to compensate for the lower projected risk-free rate of 4.53%. This is simply an adjustment that has no little to no validity and assumes that MRP levels adjust as interest rates change. She provides no support for this proposition.

Comparison of CAPM Estimates of AG and Company High Cases

Line		AG Case*	Company High Case Results** Trad. MRP	Projected MRP
1	Market Risk Premium (MRP)***	7.45%	7.29%	9.96%
2	Beta (based on proxy group companies)	0.74	0.70	0.70
3	MRP x Beta	5.53%	5.09%	6.96%
4	Risk Free Rate	4.35%	4.88%	4.88%
5	**CAPM Result (L 3 + L 4)**	**9.88%**	**9.97%**	**11.84%**

* Exh. AG-24
** From Exh. A-14, Schedule D5.5, pages 1 and 3

Q. PLEASE PROVIDE YOUR ASSESSMENT OF THE COMPANY'S PROJECTED CAPM MARKET RISK PREMIUM OF 9.96% ON LINE 1 IN THE CHART ABOVE.[86]

[86] Exhibit A-14, Schedule D5.5, page 1, column 7.

A. In addition to calculating the MRP rates discussed above, Ms. Nelson developed still another projected MRP based on projected stock price growth rates and dividends over the next three to five years from a select group of companies in the S&P 500 stock index**.** Based on a subset of S&P 500 companies, Ms. Nelson calculates a forecasted stock market return of 14.84% based on Value Line growth factors. From this percentage, she subtracts her current 30-year U.S. Treasury risk-free rate of 4.88% to arrive at a forecasted MRP of 9.96%.

She multiplies the 9.96% MRP by the betas for each peer company and adds the result to the 4.88% projected Treasury Bond rate to arrive at a 11.84% CAPM cost of capital rate.

There are two major flaws with this approach to developing an MRP. First, short-term fluctuations in the projections of stock market returns for the sample companies can cause the forecasted MRP rates to vary significantly. Second, many large technology companies with high growth prospects have a larger than normal weighting in the calculation of the 14.84% return due to their relatively large market capitalization. This overweighting of large technology stocks is minimized if, instead, she had used the historical market return rates from 1926 to 2024.

Q. PLEASE EXPLAIN FURTHER THE SHORTCOMINGS WITH THE MARKET RISK PREMIUM DEVELOPED BY WITNESS NELSON.

A. Witness Nelson is using an extremely short period of 3 to 5 years to measure stock market returns in determining the MRP. The projected MRP does not include a complete cycle of economic expansion and contraction, which is what occurs over the long-term. To adopt

the Company's approach would be akin to only selecting the positive return years over the 99-year historical period of stock market returns and not the losses in the downturn years. Expectedly and incorrectly, we would derive a far higher overall return for the market and far higher market risk premium, which is the flawed result achieved by witness Nelson in the 14.84% market return and forecasted MRP of 9.96%.

These concerns are also echoed by Dr. Roger Morin, a recognized expert on regulatory finance matters, who strongly supports the use of the longest possible period for calculating a market risk premium. On page 114 of his book "New Regulatory Finance" Dr. Morin states the following:

> Therefore, an historical risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earn a lower risk premium than they expect are offset by short-run periods during which investors earn a higher risk premium than they expect. Only over long time periods will investor return expectations and realizations converge. Clearly, the accuracy of the realized risk premium as an estimator of the prospective risk premium is enhanced by increasing the number of years used to estimate it….

Clearly, Ms. Nelson's approach to calculating the projected market risk premiums is not academically or practically sound.

For the above reasons, Ms. Nelson's development of the forecasted MRP used by the Company in the CAPM and ECAPM cost of equity calculations is seriously flawed and should be rejected.

Q PLEASE COMMENT ON MS. NELSON'S USE OF THE ECAPM METHOD.

The basic premise for the use of the ECAPM method is that the Beta factors published by Value Line when used in CAPM analysis do not accurately predict stock performance.

However, this argument is flawed. Notwithstanding Ms. Nelson's arguments, there is academic disagreement with the validity of the original studies that led to the use of ECAPM. First, the original study used raw betas and not the adjusted Value Line betas, which I use, and other cost of capital experts normally rely upon. Second, the original studies relied upon short-term risk-free rates. Instead, cost of capital witnesses, including myself, who have been involved in the Company's rate cases, use long-term risk-free rates in the CAPM model.

Dr. Morin points out this key difference on page 191 of his book "New Regulatory Finance" where he states that "…the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free rate version which has been tested."

The ECAPM produces a faulty cost of equity rate with a bias toward overstating and inflating the true cost of equity capital. The Commission should continue to disregard this alternative approach to the traditional CAPM method.

Q. HAVE OTHER REGULATORY COMMISSIONS WIDELY EMBRACED THE ECAPM METHODOLOGY FOR SETTING RETURN ON EQUITY RATES?

A. No. The Attorney General asked the Company if other regulatory commissions supported ECAPM and to provide copies of rate orders from those regulatory jurisdictions. In

response, the Company stated that the ECAPM methodology was accepted in Mississippi, Alaska, New York, North Carolina, and Maryland.[87]

The Company cited three cases from North Carolina decided in 2025, 2023, and 2020. A review of the 2025 case decision identifies Ms. Nelson as the sponsor of the ECAPM estimates but it is unclear that the North Carolina commission relied upon this information.

Regarding the purported acceptance of the ECAPM in the State of Mississippi, the filing requirements of the Mississippi Commission required ECAPM filings in the past. The case referenced by the Company is from 2001. Based upon my review of this case, which is 25 years old, the extent to which Mississippi currently relies upon ECAPM estimates is unknown. The New York case noted by the Company identifies the use of the "zero-beta CAPM" but it is unclear that this methodology is analogous to ECAPM.

As for the Alaska case noted by the Company, this case dates back to 2002. It is unclear whether the Alaska commission currently gives any weight to ECAPM, given the age of this case cited by the Company. Regarding the Maryland Commission's use of the ECAPM, the Company cited case 9311 from 2013 as an example. However, in a more recent case involving PEPCO (case 9418) with an order issued on November 15, 2016, the result is different. As shown in the summary positions articulated in the order in this case, no party involved in the proceedings, other than the utility, put forth an ECAPM ROE estimate. In this case, the Maryland commission basically adopted the Staff's position with no ECAPM estimate and rounded down the Staff's recommended ROE of 9.57% to

[87] See AGDE-1.12b

9.55%. The Maryland commission expressed no position on ECAPM. I am not aware of any more recent cases that show a change in the commission's view of the ECAPM methodology.

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE APPROVED IN THE PAST TWO YEARS FROM OCTOBER 2023 TO SEPTEMBER 2025.

A. Exhibit AG-28 shows the ROEs approved by state regulatory commissions for U.S. gas utilities during the most recent two years ended September 2025. The majority of the 40 ROE decisions in the 12 months ended September 2024 and the 43 decisions in the subsequent 12 month period ended September 2025 are at rates well below 9.8%, which is DTE Gas's current authorized ROE.[88] As shown on page three of the exhibit, three decisions in the 12 months ended September 2024 and seven decisions in the 12 months ended September 2025 are at rates of 9.9% or greater. These higher rates are primarily from regulatory commissions in California and Florida, and several pertain to small companies or other special situations. ROEs in California have been at or above 10% reflecting the unique challenges for utilities in that state with frequent wildfires and earthquakes risk. ROEs in Florida reflect damage to utility property and financial losses from hurricanes, which is an on-going challenge for the utilities in the state. High ROEs

[88] The decisions for the periods ended June 2024 and June 2025 are from RRA and exclude Limited Issue Rider cases.

in other jurisdictions tend to reflect smaller utilities or unique geographical challenges, such as in Alaska.

For most of the other gas utilities that have business and financial risks comparable to DTE Gas's operations, the ROE rates have averaged between 9.53% and 9.64% in the past two years. This evidence supports a lower overall cost of equity than the Company's current ROE rate of 9.80%. This ROE rate is somewhat excessive when compared to other gas utilities. The Company's proposed ROE rate of 10.25% is even further removed from reality and clearly unsupportable. My recommended ROE rate of 9.80% in this rate case is quite reasonable and consistent with the Commission's prior ROE decision for DTE Gas.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR EXHIBITS AG-26 AND AG-30.

A. Exhibit AG-26 shows the percentage of non-utility and non-regulated operations for each of the peer companies. In general, approximately 20% of the total operations of these companies are from non-utility or non-regulated businesses. These businesses do not benefit from regulatory protection and they are usually riskier than utility operations. Therefore, when considering an appropriate ROE rate for the Company, it is important to keep in mind that the cost of equity capital calculated from these companies reflect higher risks than the operations of DTE Gas, which is purely a gas utility company with less risk than the peer group.

Exhibit AG-30 shows the average ROE rate of 9.66% for the gas utilities in my peer group. This is another benchmark that shows the 9.80% ROE rate I have proposed is reasonable if not generous for the Company in this rate case.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE OF 9.80% IN THIS CASE WILL LEAD TO IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?

A. No. From time to time in previous general rate cases, certain applicants, including the Company, have raised arguments that they should receive higher ROEs to ensure the financial soundness of the business and to maintain a strong ability to attract capital in addition to being compensated for risk. However, those concerns are not supported by the evidence. Exhibit AG-28 shows several gas utilities that have accessed the capital markets at competitive interest rates since receiving an ROE near or below the 2025 average rate of 9.64%.

As shown on Exhibit A-17, Schedule G2, the market for new utility debt issues has been very robust, with over 200 new issues completed through early October 2025. For example, DTE Energy issued $1.1 billion of new debt in February 2025 and DTE Electric issued $1.3 billion of new debt in May 2025. Also, as shown in Exhibit A-14, Schedule D2, DTE Gas issued $260 million of new debt in September 2025. Accordingly, the debt markets have been receptive to utility companies' capital raising activities.

Similarly, there is no evidence that equity investors have abandoned utilities that have been granted ROEs near or below the industry average. On the contrary, stock investors

continue to migrate to utility stocks, recognizing that authorized ROEs are competitive. Exhibit AG-27 shows the market to book ratios for each of the peer group companies. The group of companies has an average Market to Book common equity value ratio of approximately 2.0 times, meaning that they are earning returns above the expected return on book equity capital. Interestingly, many of these companies received rate orders during the past few years with ROEs as low as 9.40% and their stock still trades above book value.

A market to book value greater than 1.0 shows that investors are attracted to the return (ROE) earned by utilities on their book value. A higher market to book ratio indicates that the utility is earning a return on book value that is higher than the investor expects for that type of investment and is willing to pay a higher market price for the stock than book value.

This information is provided to dispel the myth that the Company must receive a high ROE, above the industry average, or it will face dire consequences in the financial markets.

The fact that the Company 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. Most gas utilities face the same issues and are able to raise capital with ROEs at or near the 9.6% average rate. Therefore, this issue is another "red herring."

Q. ON OCCASION IN PAST RATE CASES, THE COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO AUTHORIZE A HIGHER ROE RATE. SHOULD STOCK MARKET VOLATILITY OR THE VIX INDEX BE A CONCERN IN ESTABLISHING A FAIR ROE RATE FOR THE COMPANY?

A. No. The stock market has historically been very volatile. Currently, this is measured by the VIX, which portrays volatility over the next 30 days. In some periods, stock prices move up and down more dramatically than at other times. The key factor is that the VIX is telling us something about risk in the market over the next 30 days and not the risk several months in the future. In setting ROE rates for utilities, the Commission's focus is the long-term financial health of the utility, not the short-term gyrations of the stock market.

As a supporting point, in Exhibit AG-35, I have included a Value Line Funds article written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not risk. Mr. Appel goes on to say later in this article that "…volatility is only risk if you act during down times, that is, only if you sell a stock." This principle still applies to events today.

Additionally, I will submit that those who invest money in equity portfolios over longer periods of time and particularly in utility stocks have an aversion to market volatility and the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as in the general stock market. This is reflected in the average Beta value of 0.74 of the utility peer group used in the CAPM discussed earlier, in contrast with the general stock market value of 1.0. The recent stock market volatility in April 2025 due to the imposition of trade tariffs is an example where utility stocks have outperformed the general stock market as a safer heaven for

investment.[89] Therefore, the Commission should not give any weight to arguments that the Company's ROE should reflect investors' concerns with stock market volatility.

Q. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE RETURN ON EQUITY RATE THAT THE COMMISSION SHOULD APPROVE IN THIS RATE CASE.

A. In Exhibit AG-22, I summarized the cost of equity rates from the three methods I discussed above. The range of returns for the industry peer group is from 9.40% at the low end, using the Utility Risk Premium approach, and 9.96% at the high end using the DCF approach.

In this regard, on line 4 of Exhibit AG-22, I have calculated a weighted return on equity from the three methodologies using a 50% weight for DCF and 25% for each of the other two methods. The result is a weighted average cost of common equity of 9.80%.

I recommend that the Commission take note of the evidence and arguments I have presented in my testimony and grant the Company a ROE rate of no more than 9.80%.

VII. Revenue Adjustments

Q. WHAT ADJUSTMENTS ARE YOU PROPOSING WITH REGARD TO THE COMPANY'S FORECASTED REVENUE FOR THE PROJECTED TEST YEAR?

[89] For example, from the end of 2024 and through April 15, 2025, the price of DTE Energy common stock was up 10.1% while the S&P 500 Index was down 8.2%.

A. In my analysis, I have discovered that the Company's projected revenues for End-User Transportation, Midstream Services, and the Appliance Service Program are significantly understated. The total incremental revenue that I propose is $24,271,000. In the testimony below I explain further the reasons for this proposed revenue adjustment.

A. End-User Transportation (EUT) Revenue

Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S PROJECTED LEVEL OF GAS DELIVERIES TO END-USER TRANSPORTATION CUSTOMERS?

A. In Table 2 on page 21 of her direct testimony, Ms. Huffman shows the calculation of 61.9 Billion Cubic Feet (Bcf) representing the five-year average of gas deliveries to power generation customers. The Company uses this volume to forecast EUT revenues for the projected test year. In discovery, the Attorney General asked the Company to update the power generation gas deliveries through the end of 2025 and provide the same information for prior years on an annual calendar basis. The updated information shows that the most current five-year average of power generation gas deliveries is 63.3 Bcf.[90] This volume is 1.4 Bcf higher than the 61.9 Bcf calculated by the Company.

[90] Exhibit AG-36 includes DR AGDG-2.48a.

The additional 1.4 Bcf multiplied by the average revenue rate of $0.147 per Mcf results in incremental revenue of $206,000.[91] I recommend that the Commission increase the Company's forecasted revenue by this amount.

Q. HAS THE COMPANY UNDERSTATED THE FORECASTED POWER GENERATION VOLUMES IN PRIOR RATE CASES?

A. Yes. In response to discovery, the Company provided a comparative schedule of power generation volumes forecasted in the last four rate cases and the volume actually delivered. Except for Case No. U-20940, in the other three prior cases the Company understated the projected test year volumes by between 2.6 Bcf and 17.5 Bcf in certain years.[92]

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO END-USER GAS TRANSPORTATION DELIVERIES AND RELATED REVENUE FOR THE PROJECTED TEST YEAR?

A. Yes. On page 2 of Exhibit A-15, Schedule E7, the Company shows a reduction of 769 MMcf for the projected test year for Energy Optimization for ST and LT rate schedule customers. In discovery, the Attorney General asked the Company to provide the calculation supporting this volume reduction and provide evidence that historical ST and LT customers have achieved a similar level of energy optimization reduction. In response, the Company provided the requested calculations showing that it assumed a 1% energy

[91] XXLT customers 2024 revenue of $9,594,000 (Exhibit A-13, Schedule C3.2) ÷ 65,150,000 Mcf (Exhibit A-15, Schedule E7) = $0.147 x 1,400,000 Mcf = $206,000.
[92] Exhibit AG-36 includes DR AGDG-2.49.

optimization reduction for gas deliveries in 2025, 2026, and through September 2027. The response also stated that the Company could not definitely attribute actual volume lost per year to customer energy efficiency and it simply assumed that EWR proposed efficiency goals would be met.[93]

From the Company's response, it is apparent that the forecasted reduction in volumes is not based on any actual evidence that the 1% of forecasted energy optimization has been achieved in the historical period and is grounded in reality. Due to the lack of evidence, the volume reduction and related revenue should be removed from this rate case. Based on the average rate of $1.188 per Mcf, I calculated incremental revenue of $914,000 for the projected test year by removing the unsupported 769,000 Mcf of energy optimization volume reductions.[94]

Therefore, I recommend that the Commission increase the Company's forecasted revenue by $914,000.

B Midstream Services Revenue

Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S PROJECTED LEVEL OF REVENUE FOR MIDSTREAM SERVICES?

A. In Exhibit A-13, Schedule C3.3, Ms. Huffman presents the Company's forecast of revenues for Contract Storage, Park & Loan, Off-system Transportation, and Exchange

[93] Id. includes DR AGDG-2.74b with attachment.
[94] ST and LT 2024 revenue of $41,113,000 (Exhibit A-13, Schedule C3.2) ÷ 34,618,000 Mcf (Exhibit A-15, Schedule E7) = $1.118 x 769,000 Mcf = $914,000.

Services for the projected test year. After reviewing Ms. Huffman's direct testimony and responses to discovery requests, I determined that the revenue forecasts for Park & Loan and Exchange are reasonable. However, I found that the revenue forecasts for Contract Storage and Off-System Transportation are significantly understated.

Q. PLEASE DISCUSS YOUR FINDINGS WITH REGARD TO THE UNDERSTATED CONTRACT STORAGE REVENUE.

A. Ms. Huffman begins the discussion of Contract Storage revenues for the projected test year on page 30 of her direct testimony. She states that as of the time she prepared her testimony the Company had already entered into gas storage contracts with other parties for 40.8 Bcf of the total available storage capacity of 62.5 Bcf. The signed storage contracts accounted for $47.1 million in revenue for the projected test year. In addition, Ms. Huffman forecasted $4.0 million in revenue for the remaining 21.7 Bcf, which is 35% of the total available storage capacity. In total, the Company forecasted $51.1 million of revenue for the projected test year.

In discovery, the Attorney General asked the Company to provide the calculations, contract volumes, contracted and assumes rates, and other data supporting the revenue forecast for the projected test year. The information provided in response to discovery shows that for the signed contracts the average rate was [Begin Conf] [redacted]

[redacted]

[redacted] [End Conf] This amount is $14,526,000 more than the Company forecasted. I recommend that the Commission increase the Company's forecasted revenue by this incremental amount.

Q. PLEASE DISCUSS YOUR FINDINGS WITH REGARD TO THE UNDERSTATED OFF-SYSTEM TRANSPORTATION REVENUE.

[95] Exhibit AG-37 CONF includes DR AGDG-2.50a-b Conf and 2.50ci-ii with attachments Conf.
[96] Id. includes DR AGDG-2.50b Conf and 8.334 Conf.

A. Ms. Huffman discusses the forecasted revenues for Off-System Transportation for the projected test year on pages 34-35 of her direct testimony. She states that the Company has already signed 59.4 million Dth of transportation service and forecasted an additional $2.0 million pertaining to transportation capacity that will be expiring soon and is likely to be sold. In total, the Company forecasted $61.4 million of Off-System Transportation revenue for the projected test year. This amount is $1.8 million lower than the actual revenue received in 2024.

In discovery, the Attorney General asked the Company to provide the detailed components of the signed Off-System Transportation service and for the expiring transportation capacity that is expected to be renewed, including volumes and rates with related revenue amounts. The information provided by the Company shows that for the signed transportation service, the Company signed 48,796,801 Mcf (or Dth) of transportation service with Off-System customers other than NEXUS, ANR and Blue Water for total revenue of $9,773,461.[97] The average rate for the Off-System customers is $0.20 per Mcf (or Dth).[98]

For the expiring capacity the information provided by the Company shows rates ranging from $0.05 to $0.28 per Mcf (or Dth) and an average rate of $0.11.[99] In comparison to the Off-System transportation contracts, which have already been signed at $0.20, the $0.11 rate is about half the present average rate. The $0.11 rate used by the Company to forecast

[97] Exhibit AG-38 includes DR AGDG-2.53a with attachment. From the information provided by the Company it is not clear if the volumes are in Mcf of Dth.
[98] $9,773,461 ÷ 48,796,801 = $0.20.
[99] Exhibit AG-38 includes DR AGDG-2.53b-c.

the revenue for the renewal of the expiring contracts is extremely understated. Using the $0.20 rate for the 19,493,786 Mcf or Dth of renewal transportation capacity results in forecasted revenue of $3,899,000. This amount is $1,849,000 higher than the Company's forecasted amount of $2,050,000. When the $1,849,000 incremental revenue is added to the Company's total forecasted revenue of $61,428,000, the total amount of $63,277,000 closely matches the 2024 actual revenue of $63,230,000.

Therefore, I recommend that the Commission increase the Off-System Transportation Service revenue forecasted by the Company for the projected test year by $1,849,000.

Q. HAS THE COMPANY UNDERSTATED FORECASTED GAS STORAGE AND OFF-SYSTEM TRANSPORTATION REVENUES IN PRIOR RATE CASES?

A. Yes. In response to discovery, the Company provided a comparative schedule of Midstream Service Revenue forecasted in the prior three rate cases and the revenue actually received for the same period. The comparison shows that Contract Storage revenue has been consistently understated, from about $1 million to nearly $9.5 million. Similarly, for Off-System Transportation, revenue has been understated by $1.2 million to $2.5 million, with the forecasted transportation rates in the last rate case being lower than actual rates.[100]

[100] Exhibit AG-39 includes DR AGDG-2.53d and 2.77c Supplemental with related attachments.

C. Appliance Service Program Revenue

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO THE COMPANY'S PROJECTED REVENUE?

A. Yes. I propose an adjustment to the Appliance Service Program's ("ASP" or "HPP") profit margin for the projected test year.[101] The profit margin is the difference between program revenues and related program expenses. In Exhibit A-13, Schedule C3, line 11, the Company forecasted the same revenue of $108.5 million for the HPP/ASP for the projected test year as it reported for 2024.

In response to discovery, the Company provided the actual revenues for the HPP/ASP from 2019 to 2025 with related operating expenses. The revenue and cost schedule with the response shows a steady increase in revenues, with 2025 revenues reaching $116.8 million, or $8.3 million above the 2024 level.[102] The schedule also shows the gross profit margin as the difference between revenues and operating expenses. From this calculation, it is apparent that the year 2024 is not representative of the revenue and profit margin earned in the most recent year of 2025, or in comparison to the trend in the most recent three years. In other words, using the 2024 revenues, operating expenses, and profit

[101] Company witness Julia Huffman discusses the HPP program beginning on page 51 of her direct testimony.
[102] Exhibit AG-40 includes DR AG-2.79a-c with attachment.

margin as a proxy for future test year amounts would result in an inaccurate and unreasonable forecast amount.[103]

Between 2022 and 2025, the gross margin increased 25%, from $32.9 million in 2022 to $41.1 million in 2025. This represents an average annual increase of approximately 8%. Applying this rate of increase to the 2025 actual gross margin results in a projected test year gross margin of $47,105,000.[104] This amount is $6,776,000 higher than the $40,392,000 forecasted by the Company for the projected test year.

Q. HAS THE COMPANY SHOWN AN INCLINATION TO UNDERSTATE THE FORECASTED REVENUE AND GROSS MARGIN OF THE APPLIANCE SERVICE PROGRAM?

A. Yes. In at least the last four rate cases, the Company has proposed to use the actual revenue amount and related gross margin from the historical test year in forecasting for the projected test year. As is evident from the uptrend in revenue in Exhibit AG-40, those forecasts have fallen short of actual results in almost every case.

Q. WHAT IS YOUR RECOMMENDATION?

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[103] In discovery, the Company provided additional revised schedules for the HPP that allocated certain internal operating costs to the HPP and presented a lower gross margin or net operating income. These internal cost allocations are not appropriate to determine the net incremental income or gross margin generated by the HPP because those allocated internal costs have not been deducted from the operating costs presented in other O&M exhibits in this rate case. Therefore, they have been disregarded.

[104] $41,147,000 x 1.08 = $44,439,000 for 2026 x 1.08 = $47,994,000 for 2027. PTY: $44,439,000 x 3/12 + $47,994,000 x 9/12 = $47,105,000.

A. I recommend that the Commission increase the Company's forecasted net revenue for the projected test year by $6,776,000. Alternatively, if the Commission does not approve the use of the historical gross margin growth rate, I recommend that the Commission adopt the actual gross margin of $41,147,000 from 2025, for a net revenue increase of $755,000 over the Company's forecast.

VIII. O&M Expense Adjustments

Q. WHAT AMOUNT OF O&M EXPENSE DID THE COMPANY INCUR DURING 2024 AND WHAT IS THE AMOUNT OF PROJECTED EXPENSE REQUESTED FOR THE 12 MONTHS ENDING SEPTEMBER 2027?

A. In 2024, the Company had total adjusted O&M expense of $433.1 million. In this rate case, for the projected test year, the Company's total O&M expense request is $543.8 million. The increase of $110.7 million, or 26% over the 33-month period, consists mainly of $27.5 million of future inflation cost adjustments plus other expense increases in the Transmission, Distribution, Marketing, and Corporate Administrative areas.

In my testimony below, I discuss several of the expense categories forecasted by the Company and propose necessary adjustments. Exhibit AG-41 summarizes the proposed adjustments discussed in my testimony.

A. Inflation Adjustments - O&M Expense

Q. DO YOU AGREE WITH THE COMPANY'S INFLATIONARY COST INCREASES INCLUDED IN THE PROJECTED TEST YEAR O&M EXPENSE?

A. No. In Exhibit A-13, Schedule C5, column (k) the Company shows that the total Other O&M expense increases by $110.7 million between the Adjusted 2024 Historical Year to the Projected Test Year. Of this amount, $27.5 million pertains to inflationary cost increases calculated by the Company. The inflationary increases are 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. The blended annual inflation rates developed by the Company are 3.0% for 2025, 2.9% for 2026, and 2.9% for 2027 (prorated for nine months), as shown on Exhibit A-13, Schedule C12. The use of a "blended rate" inclusive of wage increases has been rejected in recent general rate cases and the Commission should do so again in this rate case.[105] Instead, the Commission has previously adopted the use of the CPI-Urban area inflation rates to forecast future cost increases when warranted.

The Commission has made it clear that it expects utilities to create cost efficiencies from the implementation of IT systems and other technology, and those efficiencies should translate into tangible cost savings that reduce, and potentially even fully offset, future cost increases.

In Exhibit AG-50, I use the Company's 2024 expense base (excluding cost items that are not directly affected by inflation) to determine more appropriate inflation adjustments. For the resulting adjusted O&M expense base, I applied the inflation rates of 2.7% for 2025, 2.4% for 2026, and 2.3% for 9 months of 2027 to calculate a cumulative inflation

[105] MPSC Case No. U-21860, February 19, 2026, Order at page 78.

adjustment of $22,970,000. In comparison, the Company calculated inflation adjustments for the same 33 months totaling $27,450,000. The difference based on my lower inflation factors is $4,480,000.

The $4,480,000 reduction in inflation adjustments reflects the change from blended inflation rates to using only the CPI forecasted inflation rates. I recommend that the Commission adopt my inflation cost adjustment and remove $4,480,000 from the Company's forecasted O&M expense for the projected test year.

B. Transmission Pipeline Integrity

Q. PLEASE DISCUSS THE COMPANY'S TRANSMISSION PIPELINE INTEGRITY EXPENSE FOR THE HISTORICAL AND PROJECTED TEST YEARS.

A. Witness Scotty Kehoe discusses Transmission Pipeline Integrity beginning on page 22 of his direct testimony. In Table 5, he shows O&M expenses for pipeline integrity work increasing from $15.7 million in 2024 to $45.2 million in 2027.[106] This is an increase of 168% over a 3-year period, using the revised amount of $42.0 million provided by the Company. In his testimony, he states that the extraordinary increase in expense is driven by additional In Line Inspections (ILI) and direct assessments, with some higher activity due to compliance with the PHMSA MEGA Rule.

In discovery, the Attorney General asked the Company to explain why the amount of expense in 2024 through 2027 does not track with the number of ILI and direct

[106] In response to discovery AGDG-6.221, the Company corrected the $45.2 million to $42.0 million for 2027.

assessments. In response, the Company referred to Mr. Kehoe's testimony where he generally addresses the varying characteristics of each project but does specifically address the projects proposed each year and the related costs that justify the variances.[107] To better assess the underlying drivers of the expense for the projected test year, the Attorney General asked the Company to provide the list of projects completed from 2022 to 2025 and forecasted for 2026 and 2027 with the related costs.

The information provided by the Company shows that for 2026 the Company plans four ILI assessments, two direct assessments, and 8 remediation projects with no digs, for a total expense of $30.0 million. For 2027, the Company plans 15 ILI, one direct assessment, 18 remediations, and 285 digs for a total expense of $42.0 million. In comparison, in 2025 the Company completed 11 ILI, seven remediations, and 126 digs for a total actual expense of $34.1 million. In providing this information, the Company did not associate specific costs to the number of digs.[108] The lack of specific information for each work activity makes it nearly impossible to confirm the Company's forecasted expenses for 2026, 2027, and the projected test year.

The best information available is the number of ILI and directed assessments performed in recent years versus the Company's forecast for future years.[109] During the most recent three years 2023-2025, the Company completed 24 ILI and direct assessments, which is an average of 8 per year, at a total cost of $58.4 million for an average cost per

[107] Exhibit AG-42 includes DR AGDG-6.220c-d.
[108] Id. includes DR AGDG-6.220b with attachments.
[109] Id. includes DR STDG-2.13 Supplemental.

inspection/assessment of $2,433,000.[110] This average cost adjusted for inflation for 2026 is $2,491,000.[111] In comparison, the Company forecasted an average cost of $5.0 million per project ($30 million ÷ 6 projects).

Using the historical average cost of $2,491,000 adjusted for 2026 inflation and multiplied by the 6 projects planned by the Company results in 2026 total expense of $14,946,000. For 2027, my forecasted cost per project is $2,548,000, using the prior unit cost and adding inflation.[112] This cost is in line with the Company's forecasted cost per project of $2,625,000 ($42 million ÷ 16 projects). Using the $2,548,000 cost and multiplying by the 16 projects results in forecasted expense for 2027 of $40,768,000. Therefore, for the projected test year ending September 2027, the total expense for Transmission Pipeline Integrity work is $34,313,000.[113]

The $34,313,000 is $4,687,000 lower than the expense of $39.0 million forecasted by the Company. I recommend that the Commission reduce the Company's forecasted Transmission Pipeline Integrity expense for the projected test year by $4,687,000.

C. Transmission ROW Maintenance

Q. PLEASE DISCUSS THE COMPANY'S TRANSMISSION ROW MAINTENANCE EXPENSE FOR THE HISTORICAL AND PROJECTED TEST YEAR.

[110] $58.4 million ÷ 24 = $2,433,000.
[111] $2,433,000 x 1.024 = $2,491,000.
[112] $2,491,000 x 1.023 = $2,548,000.
[113] $14,946,00 x 3/12 + 40,768,000 x 9/12 = $34,313,000.

A. Witness Scotty Kehoe discusses Transmission Right of Way (ROW) Maintenance expense beginning on page 47 of his direct testimony. In Table 18, he shows the historical and forecasted maintenance work activity for each type of ROW maintenance. The table shows a dramatic increase in activity of more than 10 times, from 21 miles of brushing performed in 2024 to forecasted levels of 200 and 300 miles in 2025 and in 2026-2027, with additional spraying and canopy management not previously performed. Mr. Kehoe's testimony shows an increase in expense of $5.0 million over the 2024 historical year of $1.0 million.

In response to discovery, the Company provided an expanded Table 18 with the miles of ROW brushing back to 2020 and related expense. The expanded table shows that the Company performed no brushing of the transmission ROWs in 2023, performed brushing of 164 miles in 2022 for an expense amount of $1.0 million, and completed 62 miles and 11 miles in 2021 and 2020, respectively, with related expense amounts of $200,000 and $300,000.[114] To say that the maintenance activity and spending in this area has been erratic in prior years is an understatement.

In his testimony, Mr. Kehoe stated that the Company now wants to embark on a 5-year maintenance cycle and in response to discovery stated that it began to do so in 2025. The Company has 1,380 miles of transmission lines, which means that to keep a 5-year cycle, it needs to clear or brush and perform other related activities on 276 miles annually.[115]

[114] Exhibit AG-43 includes DR AGDG-6.228d.
[115] Id. includes DR AGDG-6.228a and c.

For the Company to go from zero miles in 2023 and 21 miles in 2024, to 300 miles in the projected test year, is a big jump. The Company reported that in 2025, it cleared 200 miles at a cost of $1.5 million, which is a cost per mile of $7,500. For each year, 2026 and 2027, the Company has forecasted an expense level of $6.0 million for 300 miles, at an average cost per mile of $20,000. Although the Company now wants to do some vegetation spraying and canopy management, there is no reason the cost per mile should jump from $7,500 in 2025 to $20,000 in 2026 and 2027. In response to discovery, the Company could not distinguish the separate cost for brushing, vegetation spraying, and canopy management.[116] The forecasted expenses for 2026 and 2027 appear to be rough ballpark estimates.

A reasonable expense forecast for the projected test year should be based on a manageable 200 miles of line clearing at a cost of no more than $10,000 per mile. The $10,000 represents an increase of 33% over the 2025 actual cost and should allow for the vegetation spraying and canopy management activities. The $10,000 cost per mile applied to the 200 miles results in an expense of $2,000,000 for the projected test year.

The $2,000,000 is $4,000,000 less than the Company's forecast of $6.0 million. I recommend that the Commission remove the $4.0 million from the Company's forecasted expense.

[116] Id. includes DR AGDG-6.228d.

D. Advanced Leak Detection Program Expense

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO O&M EXPENSE FOR THE PROJECTED TEST YEAR FOR THE ADVANCED LEAK DETECTION PROGRAM.

A. Beginning on page 88 of his direct testimony, Mr. Kehoe briefly discusses the anticipated notice of rulemaking from PHMSA that will likely require the Company to undertake a more extensive program to detect and repair gas leaks. In Table 37 on page 88 of his testimony, he identifies $9 million of incremental O&M expense included in the projected test year. The Company spent about $15 million on leak detection in 2024. The proposed increase would bring it up to $24 million.

In response to discovery, the Company confirmed that the final rule mandating an expanded leak detection program has not been issued by PHMSA, has been repeatedly delayed, and no approximate date for release of the final rule has been announced. The Company stated that it would prefer to proceed with an expanded leak detection program and spend an additional $9 million during the projected test year, irrespective of the final rule being issued.[117] With the Company already spending $15 million annually on leak detection and with no mandate and no significant incremental benefit identified, it would be unwise for the Company to proceed with the higher spending on its own. This is another case where customer bill affordability should prevail over incremental spending with marginal benefit.

[117] Exhibit AG-44 includes DR AGDG6.242i.

Therefore, I recommend that the Commission remove the $9.0 million from the Company's forecasted expense for the projected test year

E. Gas Leak Repairs Expense

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO THE GAS LEAK REPAIR EXPENSE.

A. On pages 95 through 97 of his testimony, Mr. Kehoe discusses the gas leak repairs backlog and in Table 39 identifies the incoming leaks, leaks repaired, the annual backlog and the capital expense to repair some of those leaks. The table does not show the O&M expense for leak repairs. In discovery, the Attorney General asked the Company to expand the table back to 2018 and provide the annual O&M expense through 2027.

In response, the Company provided the historical information and the forecasted O&M expense up to 2026. No forecasted expense for 2027 was provided. Although the capital expenditures for leak repairs are relatively stable from 2024 to 2026, the expanded table shows forecasted expense declining by $4.0 million, from $11.1 million in 2024 to $7.1 million in 2026.[118] Assuming that the 2027 expense will be similar to the 2026 forecast, the projected test year expense should be reduced by $4.0 million.

Therefore, I recommend that the Commission remove $4.0 million from the Company's forecasted O&M expense for the projected test year.

[118] Id. includes DR AGDG-6.244a.

F. Gas Leak and Work Management Systems Training Expense

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO THE GAS LEAK AND WORK MANAGEMENT SYSTEMS TRAINING EXPENSE.

A. On pages 79 through 81 of his testimony, Mr. Kehoe discusses the need for the Company to conduct employee training to use new gas leak survey technology and a new work management system. Table 32 on page 80 of Mr. Kehoe's testimony shows that the Company has forecasted $3.3 million in additional expense to conduct this training for the projected test year, with $1.8 million being outside costs and the remaining $1.5 million internal costs.

In discovery, the Attorney General asked the Company to identify what the incremental $3.3 million will be spent on and provide additional details. In response, the Company stated that $1.8 million of the incremental expense is for contractor services to bring the IFS Work Management System live and the remaining $1.5 million, including overheads, is for seven internal resources utilized for training other employees on the Work Management system and the KloudGin Leak Survey Management technology.[119]

Although the $1.8 million for external resources is an incremental cost, the $1.5 million for internal resources is not. The expense for those seven employees is already included in the Company's 2024 historical O&M expense and no reductions in other areas of the Company have been identified to offset any redirection of costs charged to training

[119] Id. includes DR AGDG-6.239a and c.

expense. Therefore, I recommend that the Commission remove the $1.5 million from the Company's forecasted O&M expense for the projected test year.

G. Damage Prevention Expense

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO THE DAMAGE PREVENTION EXPENSE FORECASTED FOR THE PROJECTED TEST YEAR.

A. On pages 84 through 86 of his testimony, Mr. Kehoe discusses the Company's proposal to add more employees to work with contractors and municipalities to prevent damage to Company facilities during construction projects. The Company states that large increases in MISS DIG staking and locating requests will require more collaboration and preconstruction meetings with excavators. Table 35 on page 85 of Mr. Kehoe's testimony shows that the Company has forecasted $2.6 million in additional expense, mostly in labor, to add more employees. Exhibit A-13, Schedule C5.3, footnote 3 shows a slightly higher increase in expense of $2,678,000 for the projected test year. This amount is probably the more accurate increase in expense from the 2024 historical year.

In response to discovery, the Company reported that it wants to add 10 additional employees with 7 damage prevention liaisons, 1 analyst, and 2 supervisors.[120] The number of existing employees currently assigned to this function is not known, but based on the $1.6 million spent in 2024, the number could be between 5 or 7 employees.[121] The

[120] Exhibit AG-45 includes DR AGDG-6.240a-b.
[121] Id.

proposed increase of 10 employees would more than double the number of employees assigned to this function.

In discovery, the Company also provided the actual number of MISS DIG tickets received from 2018 to 2025 and forecasted for 2026 and 2027. The Company received 427,543 tickets in 2024 and that number declined slightly in 2025 to 425,356. The Company forecast shows increases to 437,721 tickets for 2026 and 459,607 tickets for 2027.[122] From 2024 to 2027, the total percentage increase in MISS DIG tickets is 7.5%, assuming the forecast volumes materialize. This percentage increase does not justify more than doubling the number of employees assigned to this function.

Furthermore, no evidence has been presented that the existing employees in their role as liaisons are making a significant difference in reducing damage to facilities and that adding more employees is justified by tangible evidence. This is another case where avoidance of higher expense in support of customer bill affordability should prevail over lower priorities and marginal/unknown benefits. Therefore, I recommend that the proposed increase in staffing be rejected and the Commission disallow the incremental expense of $2,678,000 for the projected test year.

H. Staking Leadership Expense

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO THE PROJECTED TEST YEAR EXPENSE FOR STAKING LEADERSHIP.

[122] Id. includes DR AGDG-6.233b.

A. On pages 86 through 88 of his testimony, Mr. Kehoe discusses the Company's proposal to add four leadership employees to the existing six. According to Mr. Kehoe, the 10 employees would support difficult locates, ticket completion auditing, and quality review of work performed by other employees following the Company's insourcing of staking and locating work in Southeast Michigan previously performed by contractors. Mr. Kehoe states that this insourcing has been successful, but no evidence was presented in his testimony or in response to discovery to support that statement or that the 6 existing staking leadership positions are necessary. Even less evidence exists that an additional four leadership positions are needed.[123]

Table 36 on page 86 of Mr. Kehoe's testimony shows that the Company forecasted $0.7 million in additional expense in labor and non-labor for the projected test year. Exhibit A-13, Schedule C5.3, footnote 3, shows a more precise amount of $664,000 as the incremental expense for the projected test year over the 2024 historical year. In discovery, the Attorney General asked the Company to provide the year that the staking leadership program began, why the incremental four employees are needed, and identify the number of difficult locates to be addressed by the leadership employees.

In response, the Company reported that the leadership program began in 2025 with six employees, which the Company wants to increase to 10 employees in 2027. The Company also stated that the reason to add four more employees is to expand the leadership program from Southeast Michigan to the greater Michigan area. Interestingly, the Company

[123] Exhibit AG-46 includes DR AGDG-6.241b-c.

reported that it does not track or know how many difficult locates occur each year, which means that the extent of the workload for one of the major tasks of the leadership employees is unknown.[124]

In summary, the increase of four additional employees for an incremental expense of $664,000 has not been adequately supported and justified. Additionally, the Company began the staking leadership function in 2025. It should give the existing program some time to mature and assess whether the program is necessary or should be expanded. Therefore, it is premature to increase the number of employees from 6 to 10 (by 67%) after only two years. I recommend that the Commission disallow the incremental cost of $664,000 for the projected test year.

I. Regulator Station Replacement Program Expense

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO THE PROJECTED TEST YEAR EXPENSE FOR THE REGULATOR STATION REPLACEMENT PROGRAM.

A. On pages 68 through 70 of his testimony, Mr. Kehoe discusses the Company's proposal to increase the maintenance expense for regulator stations within the distribution system to mitigate over-pressurization issues. Mr. Kehoe states that the Company performs inspections of secondary regulator stations on a three-year cycle, inspects control lines associated with the service regulator on a five-year cycle, and replaces the rubber-like components of regulators on a five-year basis. He also stated that the increase in expense

[124] Id. includes DR AGDG-6.214d-f.

for the projected test year is driven by industry benchmarking and best practices. No details were provided as to what additional practices the Company is undertaking in the projected test year, but DTE Gas states that it is targeting 1,000 service and regulator inspections and 282 rubber component replacements annually.

Table 25, on page 86 of Mr. Kehoe's testimony, shows that the Company forecasted $3.1 million in additional expense in labor, materials, and non-labor for the projected test year. Exhibit A-13, Schedule C5.3, footnote 3, shows a more precise amount of $3,060,000 as the incremental expense for the projected test year over the 2024 historical year. In discovery, the Attorney General asked the Company to provide the total expense for this maintenance program for each year 2022-2025 and forecasted for 2026 and 2027, along with the number of work units.

In response, the Company reported that it incurred $1.6 million in expense in 2025 to complete 1,065 service and regulator inspections and replace 241 soft rubber goods in the regulators. For 2026 and 2027, the Company forecasted $3.6 million in expense to inspect 1,000 services and regulators and replace 282 soft goods.[125] The number of inspections in 2026 and 2027 are lower than in 2025 and the number of soft goods replacements are forecasted to increase by 17% over 2025. This level of activity does not justify a $2.0 million increase in expense between 2025 and the projected test year, or a $3.1 million increase from 2024 to the projected test year. The Company performed 1,268 service and

[125] Exhibit AG-47 includes DR AGDG-6.229a with attachment.

regulator inspections in 2024, which are nearly 27 higher than in 2026/2027, albeit with fewer soft goods replacements.

To develop a reasonable forecasted expense for the projected test year, I applied the 17% increase in the number of soft goods replacements to the 2025 actual expense of $1.6 million to arrive at an expense amount of $1,872,000. This amount is $1,728,000 lower than the $3.6 million that the Company forecasted. Therefore, I recommend that the Commission remove $1,728,000 from the Company's forecasted expense for the projected test year.

J. Employee Refresher Training Expense

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO THE EMPLOYEE REFRESHER TRAINING EXPENSE.

A. On pages 78-79 of his testimony, Mr. Kehoe briefly discusses the need for the Company to conduct periodic employee refresher training. Table 31 on page 78 of Mr. Kehoe's testimony shows that the Company has forecasted $1.9 million in additional expense to conduct this training for the projected test year, with $1.8 million being internal labor costs and $0.1 million in overhead costs.

In discovery, the Attorney General asked the Company to identify what the incremental $1.9 million will be spent on and provide additional details. In response, the Company showed that $1.471 million of the incremental expense is for employee time attending the

training sessions and the additional $0.425 million is for annual instructor costs.[126] The employees and instructors are already on the Company's payroll, and their expenses are already reflected in the O&M expense and capital expenditures for 2024. These expenses are not incremental in the projected test year. No expense reductions in other areas of the Company have been identified to offset any redirection of costs charged to training expense. Therefore, I recommend that the Commission remove the entire $1,896,000 from the Company's forecasted O&M expense for the projected test year.[127]

K. Public Awareness Program Expense

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO THE COMPANY'S PROJECTED TEST YEAR EXPENSE FOR THE EXPANDED PUBLIC AWARENESS PROGRAM.

A. Beginning on page 81 of her direct testimony, Ms. Huffman discusses the requirements and guidance offered by federal rules and industry guidelines for the Company to have in place an effective public awareness program to inform customers and the public in general about the safety risk of natural gas facilities and gas leaks. Some of these requirements are not new and the Company has had a public awareness program in place for many years, if not decades, through bill inserts, print advertising, radio advertising, and other communication channels to alert customers and the public as to what to do when smelling gas and digging near gas pipelines, including the need to call MISS DIG to locate and

[126] Exhibit AG-48 includes DR AGDG-6.237c with attachment.
[127] Exhibit A-13, Schedule C5.3, Footnote 3.

stake gas facilities before doing any digging in any location. More recently, the Company has started using employees to meet with local building contractors, excavators, and other parties to educate them on the dangers of damaging gas pipelines and the need to pre-locate underground facilities.

In 2025, the Company spent $456,000 on various media and communication activities.[128] For the projected test year, the Company proposes to spend an additional $2.0 million to undertake additional activities. These additional activities include: (1) a school visit program at an annual cost of $250,000; (2) additional direct mailings at a cost of $220,000; (3) TV, radio, and digital advertising at an additional cost of $1.415 million; and (4) $115,000 for additional incidental expenses.[129]

Although some additional public awareness may be useful, the increase in spending of $2.0 million in one year is excessive. The Company needs to be more gradual and measured in increasing spending by introducing new activities that have the largest impact at the lowest cost, and keeping in mind that customer bill affordability is of paramount importance. An increase of $1.0 million in spending in the projected test year would increase the total spending from about $0.500 million to $1.500 million or a tripling in funding for the program.

[128] Exhibit AG-49 includes DR AGDG-2.66a-c.
[129] Id. includes DR AGDG-2.70.

Therefore. I recommend that the Commission approved an increase of $1.0 million in expense and disallow the remaining $1.0 million from the Company's forecast for the projected test year.

L. New Hire VEBA Expenses

Q. THE COMPANY FORECASTED NEW HIRE VEBA EXPENSES OF $3.2 MILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS FORECASTED AMOUNT?

A. No. Line 4 of Exhibit A-13, Schedule C5.9, shows a forecasted expense of $3.2 million for New Hire VEBA. The forecasted expense is 45% higher than the 2024 historical year expense of $2.2 million before adjustments. The New Hire VEBA is a benefit plan that provides benefits to employees not covered by the Company's traditional health care benefits. Expenses increase over time as the number of participants in the plan increases.

Company witness Michael Cooper discusses the New Hire VEBA program beginning on page 10 of his direct testimony. He discusses certain adjustments made to the 2024 historical expense, including the increase in negative true-up expense. He states that the 2024 negative true-up expense was higher than usual due to some on-going effects from Covid-19. However, this conclusion seems far-fetched given that 2024 is four years after the breakout of Covid-19. Additionally, in response to discovery, the Company reported that the 2025 true-up negative expense was in excess of $1.0 million and has increased by

two and a half times since the $457,000 reported in 2022.[130] Therefore, it is likely that the negative expense will continue to increase in future years. No evidence to the contrary has been presented by the Company. In calculating the VEBA expense for the projected test year, the Company used a five-year historical negative average expense of $278,843, which is wholly inadequate given the more recent experience.[131]

Q. PLEASE EXPLAIN YOUR OTHER KEY FINDINGS FROM REVIEWING THE DISCOVERY MATERIAL PROVIDED BY THE COMPANY.

A. The model used by the Company to calculate the VEBA expense for the projected test year includes assumptions about increases in employees participating in the benefit program. For each year 2025 to 2027, the model assumes additions of 227 employees, for a cumulative total of 681 employees.[132] This is a 23% cumulative increase over 2024 and goes counter to the decline in participants observed, from 3,006 in 2024 to 2,910 in 2025. In response to discovery, the Company provided a list of participants from 2018 to 2027, showing an even higher number of participants for the projected test year, potentially reaching 3,629, with most of the increase coming from the Corporate Services Group, LLC.[133] The Company's forecasted rate of growth in the model is not sustainable or credible and significantly overstates the Company's forecasted expense for the projected test year.

[130] Exhibit AG-52 includes DR AGDG-7.319c.
[131] Id. includes DR AGDG-7.319a with attachment.
[132] Id.
[133] Id. includes DR AGDG-7.319b.

Q. PLEASE EXPLAIN YOUR PROJECTION OF THE NEW HIRE VEBA EXPENSE FOR THE PROJECTED TEST YEAR.

A. My projection of the New Hire VEBA expense is shown in Exhibit AG-51. To arrive at a reasonable expense for the projected test year, I determined the average annual increase in the number of participants from 2018 to 2025. During this period, the Company added 175 participants annually. This number of participants added to the actual participants of 2,910 in 2025 represents an increase of 6.0% for 2026. Similarly, adding 175 participants to the 2026 base of participants results in an increase of 5.7% in new participants for 2027.

I used those annual percentage increases applied to the actual 2025 VEBA expense of $2,097,000 provided by the Company to forecast the expense of $2,318,000 for the projected test year. The 2025 actual expense is the most recent and reliable base to forecast the expense for the projected test year. The $2,318,000 forecast I developed is $880,000 lower than the Company's forecast of $3,198,000. I recommend that the Commission remove the $880,000 excess expense from the Company's forecasted O&M expense.

Q. IS THERE EVIDENCE THAT IN THE LAST RATE CASE THE COMPANY OVERSTATED THE PROJECTED TEST YEAR EXPENSE FOR THE NEW HIRE VEBA PLAN?

A. Yes. In response to discovery, the Company showed that in Case No. U-21291 it had forecasted $3,256,000 in expense for the projected test year ending September 2025, but

the actual expense for that same period was $2,211,000.[134] Therefore, DTE Gas overstated the expense by $1,045,000.

M. Savings Plan Expense

Q. THE COMPANY FORECASTED $13.3 MILLION OF EXPENSE FOR THE EMPLOYEE SAVINGS PLAN FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THAT FORECAST?

A. No. As shown on line 5 of Exhibit A-13, Schedule C5.9, the actual Savings Plan expense was $10.2 million in the 2024 historical year, before certain adjustments proposed by the Company. The Company's forecasted expense of $13.3 million for the projected test year represents a 30% increase over the actual 2024 expense. Beginning on page 10 of his direct testimony, witness Matthew Fix discusses the contributions made by the Company to the savings plan for the benefit of its employees, which can reach up to 10% of an employee's base salary.

In addition, he discusses certain adjustments made to the 2024 historical expense and the assumptions used for salary increases and increases in new employee participation. The result is a total forecasted expense of $13.266 million for the projected test year, which Mr. Fix characterizes as an average annual increase of 8.5%. This percent is actually understated if the $13.266 million is compared to the actual expense of $10.235 million in 2024. The actual cumulative increase is 29.6%, or nearly 11% per year over the 2.75 years

[134] Exhibit AG-55 includes DR AGDG-2.25a with attachment.

from the end of 2024 to the end of September 2027. This rate of increase is excessive and reflects certain, unrealistic assumptions about the number of employee additions.

In response to discovery, the Company provided the calculations to arrive at its forecasted expense. Those calculations assume that the Company and the Corporate Service Group LLC will add 1,729 employee participants to the total savings plan from 2024 to 2027.[135]

Q. WHAT IS THE SAVINGS PLAN EXPENSE THAT YOU PROPOSE FOR THE PROJECTED TEST YEAR?

A. To determine a reasonable forecast for the savings plan expense for the projected test year, I calculated the average growth rate of the historical expense from 2020 to 2025. The average growth rate over this five-year period has been 3.63%, with specific years ranging from between -2% to 9%. This average growth rate reflects the increase in savings plan participants and wage increases and represents a reliable basis to forecast future increases in the savings plan expense.

As shown in Exhibit AG-54, I applied the 3.63% growth rate to the most recent actual savings plan expense of $11,161,000 for 2025 to arrive at a forecasted expense of $11,881,000 for the projected test year. This amount is $1,385,000 lower than the Company's forecasted amount of $13,266,000. I recommend that the Commission remove the $1,385,000 from the Company's forecasted expense.

[135] Exhibit AG-53 includes DR AGDG-2.25a.

Q. IS THERE EVIDENCE THAT IN THE LAST RATE CASE THE COMPANY OVERSTATED THE PROJECTED TEST YEAR EXPENSE FOR THE SAVINGS PLAN?

A. Yes. In response to discovery, the Company showed that in Case No. U-21291 it forecasted $13,166,000 in expense for the projected test year ending September 2025, but the actual expense for that same period was $11,165,000.[136] Therefore, DTE Gas overstated the expense by $2,001,000.

N. Health Care Costs

Q. THE COMPANY FORECASTS THAT ITS ACTIVE EMPLOYEE HEALTH CARE EXPENSES (MEDICAL, DENTAL, AND VISION) WILL INCREASE FROM $16.6 MILLION IN 2024 TO $20.8 MILLION IN THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS INCREASE?

A. No. The forecasted increase in health care O&M expense to $20.8 million for the projected test year effectively represents an annualized increase of approximately 8.5% per year compared to the $16.6 million 2024 actual expense. The Company goes through several steps to arrive at the higher expense level. First, it adjusts the 2024 base expense upward from $16.6 million to $17.1 million for lag hiring and other factors. Second, the Company escalates its Medical costs, which represent over 90% of the total expense,[137] by 8.9%, 6.9%, and 6.5% for 2025, 2026, and 2027, respectively. According to page 16 of Mr.

[136] Exhibit AG-55 includes DR AGDG-2.25a with attachment.
[137] DR AGDG-7.320a.

Cooper's testimony, these escalation factors are based on input from Willis Towers Watson, a consulting firm it employs. These cost increases are excessive and well above inflationary increases experienced by the Company in recent years, as shown in Exhibit AG-56.

Q. GIVEN THESE EXCESSIVE INCREASES, WHAT IS YOUR FORECAST OF THE HEALTHCARE EXPENSE FOR THE PROJECTED TEST YEAR?

A. To determine a reasonable forecast of healthcare expense for the projected test year, I evaluated the growth rate in healthcare costs over the six-year period from 2019 to 2025. To minimize the impact of the unusual events of 2020 and 2021 during the height of the Covid-19 pandemic, I started the analysis with 2019. The unusual events from Covid-19 have since been normalized over the six-year period.

As shown in Exhibit AG-56, healthcare costs over the 2019 to 2025 period have increased at an average annual rate of 2.2%. I applied this rate of increase to the actual 2025 healthcare costs of $29,610,000 for 2026 and 2027 to arrive at the projected test year cost of $30,761,000. After allocating 39% of this amount to capital expenditures, I determined the healthcare expense of $18,764,000 for the projected test year. This amount is $1,995,000 lower than the Company's forecast. Therefore, I recommend that the Commission remove $1,995,000 from the Company's forecasted expense for the projected test year.

Q. IS THERE EVIDENCE THAT IN THE LAST RATE CASE THE COMPANY OVERSTATED THE PROJECTED TEST YEAR EXPENSE FOR THE ACTIVE HEALTHCARE PLAN?

A. Yes. In response to discovery, the Company showed that in Case No. U-21291 it forecasted $22,041,000 in expense for the projected test ending September 2025, but the actual expense for that same period was $17,861,000.[138] Therefore, DTE Gas overstated the expense by $4,180,000.

O. Incentive Compensation Expense

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S INCENTIVE PAY PLANS AND THE AMOUNT OF EXPENSE THE COMPANY SEEKS TO RECOVER IN THIS RATE CASE.

A. In this rate case, the Company seeks to recover $16.6 million of employee incentive compensation in the projected test year O&M expense.[139] Based upon the information provided by the Company, $2.6 million pertains to the Annual Incentive Plan (AIP), $9.1 million pertains to the Rewarding Employees Plan (REP), and $4.9 million pertains to the Long-Term Incentive Plan (LTIP). I will also point out that 61% of the $16.6 million requested is to recover costs related to the DTE Corporate Services LLC employees (the LLC employees) whose performance metrics are often related to the performance of DTE Energy (not just DTE Gas).

[138] Exhibit AG-55 includes DR AGDG-2.25a with attachment.
[139] Page 37 of the direct testimony of witness Matthew Fix shows $16.6 million of O&M expense for incentive compensation for both financial and operating performance measures.

2025 Annual Incentive Plan – the AIP is an annual bonus program focused on the following major categories and specific measures:

1. 40% on Financial Performance: For DTE Gas employees the metrics are DTE Gas Operating Earnings, DTE Gas Adjusted Cash Flow, and DTE Energy Earnings per Share. For the LLC employees in this plan, the financial metrics are 100% dependent upon DTE Energy EPS and DTE Energy Cash Flow.
2. 15% on Customer Satisfaction (Net Promoter Score).
3. 15% on Employee Engagement (Employee Engagement Gallup rating, OSHA Incident Rate, and DTE Energy high energy, serious injury/fatality prevention).
4. 30% on Operating Excellence (Gas Open Leak balance, Gas Distribution response time, percent of HCA pipeline miles assessed with TVC, and pressure test records remediated.)

It should be noted that the LLC employee metrics for Customer Satisfaction and Employee Engagement are dependent on all of DTE Energy performance (not only DTE Gas).

These measures are for the year 2025. A review of the measures in place for the prior five years reveals that certain measures and target levels have varied from year to year. These changes make a direct comparison over the years more challenging.

2025 Rewarding Employees Plan – The REP is very similar in design and function to the AIP, with some variations in the non-financial measures. Where the AIP is designed for senior level managers at DTE Gas and its affiliates, the REP covers all other non-union employees of these companies.

The REP is also applicable to the LLC employees providing support services to DTE Gas.

2025 Long Term Incentive Plan – The LTIP is an annual stock grant plan focused on achieving three-year goals and specifically on the following measures:

1. 80% on Common Stock Total Shareholder Return vs. a Peer Group.
2. 20% on Three Years Cumulative Operating EPS.

The testimony of Company witness Matthew Fix provides more details on the AIP, REP, and LTIP.

Q. WHAT IS YOUR ASSESSMENT OF EACH OF THESE INCENTIVE PAY PLANS?

A. My overall assessment is that the three incentive plans are too heavily skewed toward measures that directly benefit shareholders and not customers. Additionally, the customer benefits presented by the Company are based on a faulty premise of historical cost savings and on expectations that future targets of performance will be achieved.

Regarding the AIP and REP, nearly half of the incentive payout at target level relates to the Company and its parent, DTE Energy, achieving net income, earnings per share, and cash flow goals. Despite the argument by the Company that achieving these goals somehow benefits customers, there is no direct relationship to customer benefits. These goals are in place to maximize profits and increase cash flow to pay dividends to shareholders. 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. The Commission should not allow recovery of incentive payments related to these financial goals.

As to the Customer Satisfaction grouping of measures, this category in 2025 represents 15% of the total measures. However, as shown in Exhibit A-19, Schedule I5, the benefits achieved are far less than the costs as measured by the Company.

Regarding the Employee Engagement category, the measures contained therein, although worthy goals, do not rise to the level of being measures that are visible to customers, nor do they create direct customer benefits. They are primarily internal goals related to employee satisfaction and deployment of safe practices in the workplace.

As to the Operating Excellence category, the measures contained therein are basic operating goals. Again, these are worthy internal goals to measure the performance of the departments responsible for those operations, but they have no direct applicability to customers. The only measure that has any link to customers is the Gas Distribution Response Time metric, which represents a small portion of the expected payout.

Q. **WHAT IS YOUR ASSESSMENT OF THE LTIP?**

A. The LTIP is a plan strictly designed to induce management to create shareholder value. 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. The Company's total return is then measured against a group of peer companies to trigger a payout. This has nothing to do with creating direct benefits for DTE Gas customers and everything to do with creating value for DTE Energy shareholders. Similarly, the other measure, which is three-year cumulative operating EPS, is also very removed from any quantifiable benefits that directly accrue to customers.

The arguments put forth by Mr. Fix in his testimony that some of these measures will create a financially healthier company and therefore customers should pay for LTIP expenses are not convincing.

Q. **WHAT IS YOUR OPINION OF THE CUSTOMER BENEFITS CALCULATED BY MR. FIX TO JUSTIFY RECOVERY OF THE INCENTIVE PAYMENTS?**

A. In Exhibit A-19, Schedule I5, Mr. Fix presents a calculation which purports to show that the expected operating and financial cost savings in 2025 of $32.0 million will exceed the incentive plan payments by $15.4 million.

Although the Operating Excellence cost savings appear to exceed the allocation of incentive expense allocated to these measures, these cost savings are aspirational and assume future performance levels will be achieved. Actual results are doubtful. For example, in 2023 and 2024, the Company engaged in large cutbacks in operating expenses to boost profits and its ability to achieve these non-financial metrics may have become impaired.

The Company's claim that it has realized cost savings by preventing higher interest rates by managing its credit ratings is unconvincing. It is management's basic task to manage the finances of the Company so as to maintain healthy credit ratings without an incentive to do so.

Mr. Fix's calculated benefits for Customer Satisfaction and Employee Engagement have been determined by considering potential avoided costs related to customer complaints, lower employee absenteeism, higher productivity of employees, as well as fewer safety

incidents. Unfortunately, the Company has generally fallen short of its performance targets in these areas.

Q. **WHAT IS YOUR RECOMMENDATION WITH REGARD TO INCENTIVE PAYMENTS BEING RECOVERED IN CUSTOMER RATES?**

A. Page 37 of Mr. Fix's testimony shows the components of the incentive compensation expense that the Company has included in its O&M expense for the projected test year, which include $11.047 million pertaining to financial measures. For the reasons described above, I recommend that the Commission remove the entire $11.047 million related to financial performance measures.

Regarding the portion of incentive compensation relating to operating measures, my initial instinct is to disallow this portion as well in its entirety, as I have recommended in prior cases due to the fact that the Company has not made a sufficiently compelling case to justify recovery of these costs. However, I am cognizant of the fact that the Commission recently has allowed recovery of a portion of the short-term incentive pay related to operating performance measures.

In that vein, I recommend that the Commission allow recovery of only 60% of the incentive compensation expense that the Company has identified as pertaining to operating performance measures. The 60% represents the percentage of performance measures that have been achieved at target level or higher over the past five years, from 2020 to 2024. In calculating the incentive compensation expense in this rate case, the Company has assumed that it will achieve the target level for all operating performance measures. The

last five years of actual performance results show that the Company was able to achieve target level performance only 60% of the time, with certain years as low as 37% and some years as high as 89%. Exhibit AG-58 shows the source data provided by the Company and the calculation of the level of the annual performance achieved at target or better, along with the overall average percentage rate for the five years at the bottom of the schedule.

The Company proposed $5,544,000 of incentive compensation related to operating performance measures, per Table 2 on page 37 of Mr. Fix's direct testimony. However, as stated earlier, this amount assumes that 100% of the operating measures will be achieved at the 100% target level. I recommend that the Commission allow recovery of only 60% of the $5,544,000, or $ 3,326,000, and disallow the remaining $2,218,000.

Therefore, in total, the Commission should deny recovery of $13.265 million in incentive compensation expense proposed by the Company ($11.047 million related to financial measures and $2.218 million of operating measures).

P. Administrative and General Expenses

Q. WHAT ADJUSTMENTS TO THE ADMINISTRATIVE AND GENERAL EXPENSES FOR THE PROJECTED TEST YEAR DO YOU RECOMMEND?

A. As shown on page 1 of Exhibit A-13, Schedule C5.6, expenses in the Administrative and General area are forecasted to increase by $11.2 million, or 10.0%, from $114.8 million in the adjusted 2024 historical period to $126.0 million in the projected test year. The

Company's exhibit shows that the expense increase includes (a) $4.4 million for blended inflation cost adjustments; and (b) $5.2 million for increased Capital Use Charges billed by DTE Electric Company for shared facilities.

Q. THE COMPANY FORECASTED $52.2 MILLION OF EXPENSE FOR THE PROJECTED TEST YEAR FOR RENTS-SHARED ASSET CHARGES. WHAT IS YOUR ASSESSMENT OF THIS EXPENSE PROJECTION?

A. On line 16 of Exhibit A-13, Schedule C5.6, the Company shows forecasted Rents - Shared Assets expense of $52.2 million. This amount represents an increase of $8.0 million, or 18%, over the 2024 historical period. The Company bases its expense estimates for this item on projections originated in 2025, which were included in DTE Electric rate case No. U-21860.

Since then, the actual expense allocated to DTE Gas for 2025 was reported at $46.2 million, which is $0.8 million lower than the amount forecasted for the year. This information is shown and footnoted in Exhibit AG-59. Furthermore, the Company forecasted increases in shared charges for future years based on the capital expenditures and operating costs proposed in the DTE Electric rate case. That rate case (U-21860) was recently adjudicated by the Commission on February 19, 2026, and several of the capital expenditures proposed by DTE Electric pertaining to facilities and IT projects were disallowed. Therefore, the $52.2 million expense forecasted by the Company is overstated.

To determine a reasonable forecast for the projected test year, I used the most recent 2025 actual expense and increased it by the inflation rates for 2026 and 2027. The result is a forecasted expense of $47.920 million for the projected test year, as shown in Exhibit AG-59. This amount is $4.445 million lower than the $52.197 million forecasted by the Company. Therefore, I recommend that the Commission remove the $4,445,000 from the Company's forecasted expense for the projected test year.

Q. Uncollectible Accounts Expense

Q. PLEASE SUMMARIZE HOW THE COMPANY ARRIVED AT ITS PROPOSED $23.5 MILLION EXPENSE AMOUNT FOR UNCOLLECTIBLE GAS ACCOUNTS FOR THE PROJECTED TEST YEAR.

A. Company witness Jason Sparks discusses the uncollectible expense beginning on page 44 of his direct testimony and also sponsors Exhibit A-13, Schedule C5.7.

Exhibit A-13, Schedule C5.7, shows that the Company started its calculation of the uncollectible expense for the test year by using the methodology previously approved by the Commission of developing an average loss ratio from the most recent three years of net charge-offs to revenues and applying the loss ratio to future revenues to develop an estimate of uncollectible accounts expense. Mr. Sparks used the loss ratios for 2022, 2023, and 2024, which averages to 1.20%, and applied this percentage to forecasted revenues for the projected test year to arrive at the $22.496 million of uncollectible accounts expense. To this amount the Company added $1.043 million for what it calls "Historical 3-year Average Charges to Direct Expense."

In discovery, the Attorney General asked the Company to explain what these direct charges to expense are for. In response, the Company stated that in 2022 and 2023 it used some matching funds from the Michigan Department of Health and Human Services to offset bill payment arrears for certain customers. The Company claims that if those funds had not been used then it would have incurred higher uncollectible expenses in those years. This premise is unfounded and speculative.[140] Although some of those arrears may have been written off in future years, there is no direct link between payments received in one year and the eventual write-off of uncollectible accounts in future years. Furthermore, the Company receives LIHEAP assistance payments and other bill assistance payments from multiple sources and those payments are not factored *out* of the uncollectible accounts expense calculation for special treatment and recovery. Net Charge-offs also include later payment recovery of previously charged-off amounts. These payments would be similar to cash recoveries after the unpaid bills were charged-off.

Although in some prior rate cases this problem was not discovered, it does not mean it should continue. Therefore, I recommend the Commission removed the $1,043,000 from the Company's forecasted Uncollectible Accounts Expense for the projected test year.

R. Rate Case Expenses

Q. PLEASE DISCUSS YOUR PROPOSAL FOR PARTIAL RECOVERY OF RATE CASE EXPENSES INCURRED BY THE COMPANY.

[140] Exhibit AG-60 includes DR AGDG-2.21b.

A. With the Company filing rate cases nearly every year, the costs incurred to prepare, file, and litigate each case are becoming significant. Currently, the Company expenses those costs and they become part of the base O&M expenses that it recovers in rates. In this rate case, the Attorney General asked the Company to provide the total costs incurred to complete each of the last three rate cases and the number of hours spent on the case by Company employees. The Company was also asked to provide the amount paid to external consultants retained to work on the rate cases. In response, the Company provided the amounts paid to external consultants, but stated that it does not track time or internal costs spent on rate cases and could not provide that information. The Company also refused to calculate and provide an estimated amount of the internal costs incurred, claiming that this information did not exist.[141]

Q. WHAT DO THE EXTERNAL CONSULTANT COSTS REVEAL?

A. In response to discovery, the Company disclosed that for Case Nos. U-20940 and U-21291, which took place primarily during 2021 and 2024, external consultant costs ranged from $566,000 to $732,000. For the current Case No. U-21973, the Company provided two estimates ranging from $373,000 to $418,000. The $418,000 amount was included in the forecasted O&M expense for the projected test year.[142]

In the discovery response, the Company stated that one consultant provided expert witness testimony on the return on equity rate [Begin Conf] [redacted]

[141] Exhibit AG-61 CONF includes DR AGDG-3.98a-c and 3.99a-b with Confidential attachment.
[142] Id. includes DR AGDG-8.343b Confidential.

[redacted] [End Conf] The Company claims that the increase in intervenors in the rate cases and discovery requests has necessitated the use of external legal counsel.[143]

Q. PLEASE PROVIDE AN ASSESSMENT OF POTENTIAL RESOURCES AND COSTS FOR THE COMPANY TO PREPARE AND COMPLETE A RATE CASE.

A. In the current rate case, DTE Gas filed approximately 1,800 pages of testimony with more than 300 exhibits plus supporting schedules and workpapers, prepared by 22 witnesses or assisted by others in the Company and outside consultants. The testimony and exhibits most likely went through multiple levels of review and analysis involving more people than the 22 witnesses who filed testimony in the case.

The external consultant in the current rate case who filed testimony on the return on equity, filed 110 pages of testimony and exhibits at a cost of approximately $500 per page. If I apply this cost as a proxy of the actual cost for the Company to prepare the 1,800 pages of testimony and other documents filed in this case, the base testimony preparation cost is $900,000. This does not include the time and cost for supervisory review, legal review,

[143] Id. includes DR AGDG-8.343a.

responses to discovery requests, support functions, legal briefs, and myriad other tasks. If I apply a factor of 3 times to the $900,000, the total cost for the Company to prepare and complete a rate case likely exceeds $2.7 million.

Such a cost is a significant burden to customers if the utility continues to recover 100% of that expense.

Q. ARE YOU AWARE OF ANY REGULATORY PRACTICES IN OTHER STATES THAT SHARE THE BURDEN OF RATE CASE EXPENSES BETWEEN CUSTOMERS AND SHAREHOLDERS?

A. Yes. My understanding is that the states of Connecticut and Colorado have statutes that exclude rate case expenses from rate recovery. New Jersey and Missouri have regulatory commission precedents splitting rate case expenses 50/50 between customers and shareholders.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that in this case the Commission disallow recovery of at least 50% of the $418,000 of the external consultant costs, or $209,000, from the projected test year O&M expense. Additionally, I recommend that the Commission direct the Company to establish a mechanism to keep track of all costs to complete future rate cases and provide that cost with each new rate case filing.

S. O&M Expense Summary

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR O&M EXPENSES.

A. Operations and maintenance expenses represent a large part of the Company's cost structure. My analysis of the expense level proposed by the Company has determined that expenses in certain areas are excessive or unnecessary and should be removed. I recommend total reductions to O&M expenses of $58.9 million as discussed above and summarized in the following table. Exhibit AG-41 provides additional details of the areas where I propose O&M expense adjustments.

Summary of O&M Expense Reductions	Amount ($Millions)
Inflation Reduction	$ 4.5
Transmission Pipeline Integrity Expense	4.7
Transmission ROW Maintenance	4.0
Advanced Leak Reduction Program	9.0
Gas Leak Repair, Detection and Training	5.5
Damage Prevention amd Staking Leadership	3.3
Regulator Station Replacement	1.7
Employee Training	1.9
Public Awareness Program	1.0
Employee Benefits	4.3
Incentive Compensation	13.3
Other Expenses	5.7
Total Reductions	**$ 58.9**

IX. Depreciation Expense

Q. **DO YOU PROPOSE AN ADJUSTMENT TO DEPRECIATION EXPENSE FOR THE PROJECTED TEST YEAR?**

A. Yes. As a result of the reductions in capital expenditures proposed above in my testimony and the impact on capital additions included in rate base, I have calculated a reduction in

depreciation expense of $5,328,000. The calculation of this amount is shown in Exhibit AG-18.

I recommend that the Commission reduce the depreciation expense proposed by the Company for the projected test year by $5,328,000.

X. Property Tax Expense

Q. PLEASE DISCUSS THE PROPERTY TAX EXPENSE ADJUSTMENT THAT YOU PROPOSE.

A. In Exhibit AG-18, I identified the adjustments to be made to the Company's proposed capital expenditures. Those reductions lower the amount of property tax expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in property tax expense of $1,007,000. I recommend that the Commission reduce the Company's property tax expense by this amount for the projected test year.

XI. Gas Main Replacement Program (MRP/GRP) and IRM

As shown in Exhibit A-12, Schedule B5.3, the Company spent $357.8 million in 2024 under the Infrastructure Recovery Mechanism (IRM) and forecasted $343.5 million for 2025 and $344.3 million for 2026, consisting of the total of the first 9 months of 2026 and the spending in the last three months of 2026 shown under the 12-month period ending September 2027. The Company also proposes to continue the IRM for the five calendar years 2027 to 2031, with annual spending levels from $378 million to $455 million. Included in the IRM are the Main Replacement Program (MRP), the Meter Move-Out

(MMO) program, the MMO MAC Initiative program, the Pipeline Integrity program, and in this rate case, the Company proposes to also include the Cathodic Protection, the Ultrasonic Meter Replacement, and the Regulator Station Replacement programs.

Mr. Eric Janness's direct testimony discusses each of these programs and the IRM proposed expenditures from 2024 to 2031.

Q. WHAT IS YOUR ASSESSMENT OF THE LEVEL OF SPENDING PROPOSED BY THE COMPANY IN THE MRP, GRP, AND THE IRM?

A. The Company has continued to escalate the size of the program in each subsequent rate case, following approval of the MRP in 2010. Although not fully evident in Exhibit A-12, Schedule B6, the Company proposed the MRP for the first time in August 2010 in Case No. U-16407. At that time, the Company proposed to replace 30 miles of targeted mains for annual capital spending of $17.4 million. Shortly thereafter, in 2012, in case No. U-16999, the Company proposed, and the Commission approved, an escalation of the program for replacement of 66 miles of main at an annual spending level of $46.9 million. Case No. U-16999 also established the IRM as a mechanism for the Company to more quickly recover the cost of capital additions for the MRP and other programs.

In 2014, in Case No. U-17701, the Company proposed to again increase the annual spending level to $78.3 million by 2017 and to replace 103 miles of main annually. In December 2015, the Company filed a rate case in Case No, U-17999 and requested a further increase in the capital expenditures for the MRP to $93.8 million for 2017 with plans to replace 123 miles of main. Subsequent to that rate case, the Company scaled

down the number of miles of main to be replaced but maintained the same proposed spending level.

In rate Case No. U-18999, filed in November 2017, the Company once again requested further escalations of the program capital expenditures to $169.7 million for 2019 and $193.0 million for 2020. In the subsequent two rate cases, spending levels again increased, reaching $340 million in 2022 for all the component programs within the IRM. This trend of ever-escalating spending on programs within the IRM continues in this rate case, with proposed spending of $344 million in 2025 and 2026 and higher amounts through 2031.

In other words, what began as a modest program of $17.4 million to replace cast iron mains and other unprotected and deteriorating gas mains has now mushroomed into a monstrous annual program that could reach $450 million annually with newly proposed programs.

Q. WHAT REASONS DOES THE COMPANY OFFER FOR THE FURTHER ESCALATION OF PROGRAM COSTS IN THIS RATE CASE?

A. In his testimony, Mr. Janness points to more complex projects, higher permit and restoration costs, and higher contractor costs. It appears the new probabilistic risk model is either selecting or aggregating more complex projects. Why this is occurring is not entirely clear. However, the evidence provided by the Company does not show that complex projects are a significant portion of the total number of projects completed each year. In discovery in Case U-21291, the Attorney General asked the Company to provide the list of projects from which the projects targeted for 2024 and 2025 were selected.

In response the Company provided a list of about 470 projects. On that list, the number of identified complex projects is less than 20; two were completed in 2019 through 2023 and five are scheduled for 2024.[144] In the current case, the Company provided similar information that does not show project complexity has changed much over time or that "complex" projects make up the majority of the projects completed each year.[145]

With regard to cost increases, higher permit costs, restoration costs, and contractor costs are a function of activity and the increased demand for services placed on those organizations by the Company and other utilities. More projects require more resources to review and issue permits. More damage to streets and sidewalks inconvenience customers and the public and there is more demand by municipalities for a wider restoration span around the project damage area. More projects also increase the cost of materials from pipe to valves and trench filling materials. Demand for contractor services has also been increasing as other utilities regionally and around the country have expanded their main replacement programs and have increased construction activity. With higher demand for resources and materials, prices for contractor installation services increase and so does the cost of completing construction projects.

This dramatic increase in demand for contractor services with limited availability of resources has resulted in significant annual cost escalations. Unless the demand for materials, contractor services, and other services ebbs with more rational limitations on

[144] U-21291 Exhibit AG-11 includes DR AGDG-6.167a with attachment.
[145] Exhibit AG-62 includes DR AGDG-5.184a with attachment.

the pace of main replacement and construction activity by gas utilities, the cost escalation problem will not improve and in fact may get worse.

In response to discovery, the Company reported that in 2025 the cost per mile of pipe replacement for the Main Renewal Program reached $1.48 million. This is an increase of 18% over the 2024 cost per mile and 37% from the $1.08 million cost per mile in 2023.[146] This trend is extremely concerning, unstainable, and needs to be reversed quickly. The increase in cost per mile reduces the number of legacy pipes that the Company can replace with the same amount of budgeted dollars.

Q. HAS THE COMPANY PROVIDED ANY HARD EVIDENCE OR ANALYSIS TO SUPPORT THE CONTINUED ESCALATION OF THE MRP IN THIS RATE CASE OR PRIOR RATE CASES?

A. No. There has been no evidence presented by the Company that deterioration of the legacy mains is increasing in such a way as to require an increase in spending. Although reducing risk and increasing safety are laudable goals, there must be more quantitative and qualitative analysis performed, which shows that the rate of deterioration of the gas mains and services is accelerating, to justify increasing annual capital expenditures by more than 10-fold between 2010 and 2025. Without such quantitative evidence, the current pace of main replacement and the escalating capital expenditures have become totally subjective.

[146] Id. includes DR AGDG-5.177a Supplemental.

In other words, there is no compelling evidence that keeping the current pace of main replacement, let alone accelerating it, is necessary.

Q. HAS THE COMPANY SHOWN FINANCIAL DISCIPLINE IN REFRAINING FROM OVER-SPENDING ON THE MRP AND STAYING WITHIN THE ESTABLISHED COST PLAN?

A. No. In response to discovery, the Company provided an updated Exhibit A-12, Schedule B6.1, to include actual expenditures through 2025. The updated schedule shows that the Company overspent the plan by nearly $60 million in 2023, or 21%, $50 million in 2024, and $18.4 million in 2025 on the GRP and Pipeline Integrity programs. More alarming is the fact that the Company overspent each year since 2016, mostly by double digit percentages as high as 33%. Exhibit AG-62 includes the attachment to the discovery response with the amount of over-spending shown.

Q. WHAT LEVEL OF CAPITAL EXPENDITURES FOR THE MRP AND OTHER COMPONENTS OF THE IRM SHOULD THE COMMISSION APPROVE IN THIS RATE CASE?

A. The increasing cost trend of the IRM discussed above is not sustainable from a customer affordability viewpoint and must be reversed. The Commission should set a maximum budget for the Company to spend on the Gas Renewal Program and the Pipeline Integrity components of the IRM to avoid the current runaway cost. Most homeowners who pay gas bills must live within their own cost budgets and do not have unlimited resources to be able to afford ever increasing household costs. They make hard choices every day as

to where to spend their money within the available resources. Similarly, the Company needs to set an annual budget and replace and install the number of miles of main, MMO projects, and pipeline integrity projects that can be completed within a set budget, unless justified by unexpected and critical safety situations. The current practice of unlimited and increasing capital spending on the IRM programs needs to be restrained.

In the November 7, 2024 order (page 77), the Commission set a $240 million limit on the capital expenditures that the Company could include in the calculation of the IRM surcharge. I recommend that the Commission do the same in this case and set the surcharge recovery limit at $255 million, if it decides not to set a firm spending budget for the Company. The $255 million represents an increase of 3% annually for two years over the $240 million established in 2024. The inability of the Company to recover the costs of capital expenditures above the $255 million through the IRM surcharge will serve as an incentive for the Company to control spending.

Q. ON PAGE 28 OF HIS DIRECT TESTIMONY, MR. JANNESS STATES THAT THE COMMISSION LIMITATION ON CAPITAL SPENDING RECOVERABLE UNDER THE IRM SURCHARGE RESULTED IN THE COMPANY DELAYING RETIREMENT OF REPLACED MAINS. IS THIS A CONCERN?

A. No, for two reasons. First, in response to discovery, the Company disclosed that only approximately 13 miles of main were postponed. The wording in Mr. Janness' testimony misleadingly implies that the postponement was equal to the 236.6 miles of installed replacement main. Second, the Company also disclosed that when replacing legacy mains,

it leaves the old mains in place.[147] Therefore, any delays were in the switchover of customers from the old main to the new main and reporting the old mains as retired on the books of the Company.

Q. ARE THERE OTHER MODIFICATIONS TO THE COMPANY'S PROPOSED IRM THAT YOU RECOMMEND?

A. Yes. I recommend that the Commission approve the following modifications to the Company's proposed IRM and the calculation of the surcharge revenue:

1. Disallow $18.4 million of capital expenditures from excess spending under the IRM in 2025.
2. Terminate the IRM after 2027 or limit it to only three years.
3. Reject the Company's proposal to expand the IRM to include Cathodic Protection.
4. Reject the proposal to expand the IRM to include a program for Replacement of Diaphragm Meters and AMI/AMR Modules with Ultrasonic Meters.
5. Reject the proposal to expand the IRM to include a program for Replacement of Pressure Regulators.
6. Use a lower pretax overall cost of capital in the calculation of the IRM surcharge that reflects the lower risk of the investments made through the IRM program.

I will discuss each of these recommendations in my testimony below.

Q. PLEASE DISCUSS YOUR PROPOSED DISALLOWANCE OF $18.4 MILLION.

[147] Id. includes DR AGDG-5.176a-b.

A. As discussed above, over the past 10 years the Company has developed a track record of overspending on the programs within the IRM. Exhibit A-12, Schedule B6.1 makes this clear and Exhibit AG-62 (DR AGDG-5.211a Attachment) updated that list through 2025. In 2025, the Company overspent by $7.9 million on the GRP and $10.5 million on the Pipeline Integrity program for a total amount of overspending of $18.4 million. The overspending on the Pipeline Integrity program was 46%. As I stated earlier, this overspending is not sustainable and continues to negatively affect customer bill affordability when compounded over a decade of overspending, totaling $363 million from 2016 to 2025. It is past time to hold the Company accountable for the constant overspending.

Therefore, I recommend that the Commission disallow the latest amount of overspending of $18.4 million for 2025.

Q. PLEASE DISCUSS YOUR PROPOSAL TO TERMINATE THE IRM AFTER 2027 OR LIMIT IT TO ONLY THREE YEARS.

A. One of the objectives of the Commission's approval of the IRM was that it would reduce the need for the Company to file frequent rate cases. However, that objective has clearly not been realized. The Company filed this rate case less than two years after it filed the last rate case, and it will probably file another rate case soon after an order is issued in the present case. This frequent filing of rate cases defeats the need to have an IRM, because the same capital expenditures that the Company proposes for the IRM can be included in

the rate case projected test year where they can be examined more closely and holistically as part of the larger rate case.

As evidenced in this rate case, the Company splits some of the IRM expenditures for inclusion in rate base and the remainder in a new IRM year, creating confusion and extra effort to sort through all the inclusions, exclusions, and complexities.

The IRM also does not have the same visibility and does not receive the same attention and scrutiny from intervenors that occurs in a rate case. Furthermore, it creates another proceeding for reconciliation of the amounts spent, requiring additional resources to be spent on another case. Therefore, I recommend that the Commission terminate the IRM after 2027.

If the Commission rejects this proposal, alternatively I recommend that it limit the IRM to only three years. The three-year cycle provides sufficient time for the Company to implement capital programs should it decide to delay filing a rate case.

Q. PLEASE DISCUSS YOUR PROPOSAL TO EXCLUDE FROM THE IRM THE CATHODIC PROTECTION, ULTRASONIC METER INSTALLATION, AND PRESSURE REGULATOR REPLACEMENT PROGRAMS.

A. The Company is following the typical template of continuing to expand the IRM with new projects and programs. The appeal to recover the costs from capital expenditures automatically through the IRM surcharge even before the dollars are spent is too great to pass up. The Company will point to other things, such certainty of spending levels and the

like, but it is the allure of the IRM surcharge that is the driving force. The advantages that the Company identifies with the IRM can also be accomplished through general rate cases, particularly when filed every year or two.

Regarding the Cathodic Protection program, the Company made the same proposal in Case No. U-21291 and the Commission rejected that idea. There is nothing new in this rate case that makes a compelling or convincing case to include it in the IRM.

Regarding the Ultrasonic Meter Replacement program, under the Capital Expenditures section of my testimony, I stated that the Company has not presented a comprehensive plan for this program to justify undertaking it at this time. Therefore, it should not be included in the IRM. Even if the Company were to adequately justify this program in a subsequent rate case, there is no need to implement it through the IRM. When the time comes, it can propose an appropriate level of spending for inclusion in a general rate case similar to other capital programs.

The same argument applies to the Regulator Station Replacement Program. This program also needs to be better justified and can be addressed through a general rate case with proposed spending levels appropriately supported and scrutinized.

Therefore, I recommend that the Commission reject the Company's proposals to expand the IRM to include these three programs.

Q. PLEASE DISCUSS YOUR PROPOSAL TO USE A LOWER PRETAX OVERALL COST OF CAPITAL IN THE CALCULATION OF THE IRM SURCHARGE

THAT WOULD REFLECT THE LOWER RISK OF THE INVESTMENTS MADE THROUGH THE IRM PROGRAM.

A. Currently, in calculating the annual IRM surcharge revenue, the Company uses the pre-tax rate of the cost of permanent capital, consisting of the cost of the long-term debt and the common equity in the capital structure, and applies that rate to the average annual investments net of accumulated depreciation and deferred taxes. Exhibit A-18, Schedule H1, provides an example. There are two problems with the current approach in applying the standard cost of the pre-tax cost of permanent capital.

First, the IRM provides the Company with a mechanism to recover the revenue requirement for the forecasted investments for the IRM year contemporaneously with, if not ahead of, when the capital expenditures are actually incurred during the year. The IRM surcharge starts in January of each year and the Company collects most of the revenue during the winter months ahead of the spring, summer, and fall surge in capital spending. This automatic recovery of costs is generally risk-free, with no regulatory lag or disallowances. The investments made through the IRM are not comparable to investments made and recovered through a general rate case and pose considerably less risk for the Company. The current application of the normal cost of permanent capital does not reflect the significant lower risk of the IRM.

Less business risk requires a lower cost of common equity capital. With nearly guaranteed recovery of costs, the common equity rate should approximate the cost of long-term debt, similar to guaranteed interest on a long-term bond. Given that the investments through the

IRM last only one to two years, a strong argument could also be made that the equity rate of return should be even closer to the cost of short-term debt. However, at this time I propose that the ROE rate used in the overall cost of capital to be applied to IRM investments be set as the average of the Commission approved ROE rate and the cost of long-term debt. Based on the ROE and long-term debt rates approved in Case U-21291, the ROE rate for the IRM should be 7.12% or approximately 7% (Equity 9.80% x 50% + LT Debt 4.44% x 50%) instead of 9.80%. The 7.12% ROE rate applied to the capital structure results in an overall pre-tax cost of capital of 5.73%.[148] I recommend that the Commission adopt a more sensible ROE rate that reflects the significant lower risk of the IRM cost recovery mechanism.

Part 2 of my proposal is that the Company use the overall pre-tax cost of capital instead of the pre-tax cost of permanent capital to calculate the annual IRM revenue requirement. The permanent cost of capital excludes the cost of short-term debt from the cost of capital. Short-term debt is used to fund annual capital expenditures and seasonal expenditures until permanent capital is raised. Therefore, it should be a component of the cost of capital applied to capital expenditures under the IRM, along with all accumulated deferred taxes that are part of the total capital structure. I recommend that the Commission direct the Company to use the overall pre-tax cost of capital approved in each rate case with the 7.12% ROE rate in calculating the IRM revenue without any netting of the rate base for deferred taxes.

[148] Exhibit AG-63 includes the calculation of the overall pre-tax cost of capital with the 7.12% ROE rate.

XII. Adjustments To Revenue Deficiency

Q. WHAT ARE THE TOTAL ADJUSTMENTS AND THE REVISED REVENUE DEFICIENCY YOU RECOMMEND?

A. Exhibit AG-64 summarizes the adjustments to rate base and operating income. The base revenue deficiency is $109.6 million, which is a reduction of $127.9 million from the Company's rate case filing of base revenue deficiency of $237.5 million. After reflecting the termination of the customer surcharge of $74.8 million pertaining to the portion of the IRM investments rolled into rate base, the net revenue deficiency and increase in customer rates calculated by the Attorney General is $34.8 million. In comparison, the Company's net proposed increase in rates is $162.7 million, for a similar reduction of $127.9 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $109.6 million and reducing the IRM surcharge accordingly, for a net increase of $34.8 million.

XIII. Rate Design

Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR RESIDENTIAL CUSTOMERS HAS THE COMPANY PROPOSED?

A. In his direct testimony, Company witness Habeeb Maroun proposes to increase the monthly service charge for residential customers (Rate Schedules A and 2A) from $14.50 to $15.40 per month. Mr. Maroun also proposes to increase the monthly customer service charge for small commercial customers in rate schedule GS-1 from $50.00 to $55.00.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. In part. The proposed change in the residential rate from $14.50 to $15.40 per month represents an increase of 6%. For small commercial customers under rate GS-1, the increase from $50.00 to $55.00 is 10%. I find the 6% increase in the monthly charge for residential customers reasonable. For rate GS-1, the 10% increase is somewhat excessive and recommend that a 6% increase should also be applied resulting in an increase of $3.00 to $53.00 from the current $50.00.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission approve the increase in the monthly residential customer charge to $15.40. For the commercial GS-1 customers, I recommend that the Commission approve an increase of $3.00 for a monthly charge of $53.00.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does. However, I reserve the right to amend, revise and supplement my testimony to incorporate new information that may become available.

Experience and Qualifications of Sebastian Coppola

Mr. Sebastian Coppola is an independent energy business consultant and president of Corporate Analytics, Inc., whose place of business is located at 5928 Southgate Rd., Rochester, Michigan 48306.

EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for 22 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

ENERGY INDUSTRY EXPERTISE

During his 27-year career at SEMCO Energy, MCN Energy and MichCon, Mr. Coppola held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many

of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

Mr. Coppola is intricately knowledgeable of capital markets and financial institutions. As Treasurer and Vice President of Finance, he directed the issuance of more than $2 billion in securities, including common stock, corporate bonds, tax-deductible preferred stock and high-equity value convertible securities. He established bank lines of credit, commercial paper and asset acquisition facilities. He has had extensive interactions with equity and debt investors, financial analysts, rating agencies and other members of the financial community.

ENERGY INDUSTRY AND REGULATORY EXPERIENCE

As a business consultant, Mr. Coppola specializes in financial and strategic business issues in the fields of energy and utility regulation. He has more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. He has testified in several regulatory proceedings before State Public Service Commissions. He has prepared and/or filed testimony in electric and gas general rate case proceedings, power supply and gas cost recovery mechanisms, revenue and cost tracking mechanisms/riders, multi-year rate plans and incentive ratemaking, and other regulatory matters.

Mr. Coppola has extensive experience with gas and electric utilities in the areas of gas operations, gas supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared

testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General, the Maryland Office of Public Counsel, and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, DTE Electric Company, MichCon (DTE Gas Company), Michigan Gas Utilities Corp, Nicor Gas, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company, Washington Gas, and Wisconsin Public Service Company.

Mr. Coppola has also provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking. Additionally, he prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company which was filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.

As accounting manager and later financial executive for two regulated gas utilities, he has been intricately involved in construction materials procurement, gas purchase strategies and CGR reconciliation cases. He has had direct responsibility for preparing GCR reconciliation analysis and reports and supporting preparation of testimony for the cost of gas reconciliation proceedings before the Michigan Public Service Commission (MPSC). He is intricately familiar with construction projects, the power supply and gas cost recovery mechanisms, gas supply and pricing issues, and regulatory issues faced by utilities.

Experience and Qualifications of Sebastian Coppola

During his long career at DTE Gas, among other responsibilities, Mr. Coppola was responsible for overseeing the operation of the MichCon Wet Header System, a pipeline that transported natural gas and gas liquids from Michigan gas producing fields in the Niagaran Reef in the northern area of the lower peninsula of Michigan to processing plants in Kalkaska, MI. His responsibility included ensuring the day-to-day flow of gas and liquids, and identifying operating issues requiring corrective action.

He was also responsible for the study to assess the feasibility of building the Saginaw Bay Pipeline, a transmission line to move Praire Du Chein natural gas reserves in the eastern area of Michigan to processing plants. Prior to the construction of the pipeline, Mr. Coppola worked with operating management to prepare requests for proposal for the construction project and the selection of qualified bids. During and subsequent to the construction of the pipeline, Mr. Coppola assisted in the management and oversight of the pipeline, including review of operating performance and profitability.

Additionally, as Manager of Materials Inventory, Warehousing and Procurement at DTE Gas, Mr. Coppola worked closely with suppliers of pipe, control valves, flanges, meters, fittings, equipment and thousands of other parts and materials used in the construction, repair and maintenance of DTE Gas's transmission, distribution and storage facilities, including repairs and upgrades to compressor stations, and replacement of cast iron mains, bare and wrapped steel pipelines and service lines. His responsibilities included the review of design and construction blueprints and plans with frequent visits to construction sites during excavation of new pipeline trenches, and during replacement of defective or leaky

pipes, and replacement of control valves. Mr. Coppola also made frequent visits and inspection to storage facilities owned by DTE Gas to understand materials requirements during planned construction projects. Mr. Coppola was also responsible for ensuring that materials and equipment were ordered to meet material standards and safety codes.

Through these responsibilities, Mr. Coppola gained knowledge and expertise with field construction project procedures, pipeline trenching problems, installation inspections, operation and maintenance cycles, and the material procurement of pipe, valves, flanges, meters and thousands of other parts and equipment used in the construction of natural gas transmission, distribution and storage facilities.

During his career with MCN Energy Group, Mr. Coppola was responsible for the evaluation of investments in interstate pipelines, new gas storage facilities, gas cogeneration plants, and construction of new power plants in the U.S. and India. Mr. Coppola was a key member of the negotiating team with contractors and suppliers tasked to build the power facilities, including the evaluation of Engineering, Procurement and Construction (EPC) bids and contracts.

After his move to SEMCO Energy Corporation in 1999, Mr. Coppola was responsible for the acquisition and integration of pipeline construction companies providing services to gas utilities and interstate pipelines. In addition to its gas utility business in Michigan and Alaska, serving approximately 350,000 customers, SEMCO Energy owned SEMCO Pipeline Construction, a non-regulated business providing gas pipeline and natural gas facilities construction services to gas utilities and interstate pipelines in the Midwest and Eastern regions of the U.S. SEMCO

Experience and Qualifications of Sebastian Coppola

Pipeline Construction provided construction services similar to KS Energy, Northern Pipeline and other contractors used by the Company. During his tenure at SEMCO Energy, Mr. Coppola reviewed dozens of pipeline construction companies and acquired six companies. Mr. Coppola's responsibilities included management of the performance and profitability of the pipeline construction services business requiring field visits to construction projects and quality reviews. In this process, Mr. Coppola learned firsthand how pipeline construction companies operate, construction project challenges, their bidding practices and the bidding of construction projects, including pricing, bidding procedures and policies both from the contractor's side and the gas utility side.

Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

In his role as Treasurer and Chairman of the MCN/MichCon Risk Committee from 1996 through 1998, Mr. Coppola was involved in reviewing and deciding on the appropriate gas purchase price hedging strategies, including the use of gas future contracts, over the counter swaps, fixed price purchases and index price purchases.

In March 2001, Mr. Coppola testified before the Michigan House Energy and Technology Subcommittee on Natural Gas Fixed Pricing Mechanisms. Mr. Coppola frequently participates in natural gas issue forums sponsored by the American Gas Association and stays current on various energy supply issues through review of industry analyst reports and other publications issued by various trade groups.

Experience and Qualifications of Sebastian Coppola

Mr. Coppola performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, he has performed analysis of power costs and filed testimony in power supply cost recovery cases, including reconciliation of annual power supply costs.

In his position as Senior Vice President of Finance at MCN, Mr. Coppola also had responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, he was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, he was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

- **Specific Regulatory Proceedings and Related Experience:**
  - Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2024 PSCR reconciliation in Case N-. U-21426.
  - Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) proposed sale of hydroelectric power generating assets in Case No. U-21985.
  - Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2024-2025 GCR plan reconciliation in Case No. U-21446.
  - Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2024 PSCR reconciliation in Case N-. U-21424.
  - Filed testimony on behalf of the Michigan Attorney General in CECo 2025 electric rate case U-21870 on several issues, including operation

and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in DTEE 2025 electric rate case U-21860 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2025-2026 GCR plan case No. U-21608.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-2024 GCR reconciliation in case No. U-21272.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 PSCR Plan Case No. U-21594.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2024 electric rate case U-21806 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2023-2024 GCR reconciliation in case No. U-21274.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 PSCR reconciliation in case No. U-21260.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR reconciliation in case No. U-21270.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan reconciliation in case No. U-21278.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21258.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2024 electric rate case U-21585 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2024 electric rate case U-21534 on several issues, including operation

and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in the Upper Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2024 gas rate case U-21540 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2024 gas rate case U-21291 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2022-2023 GCR plan in case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Power Company 2023 electric rate Case U-21461 on several

issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in DTE 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Act 9 application in Case No. U-20993 by Saginaw Bay Pipeline Company to set transportation rates for services to DTE Gas Company.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 electric rate Case U-20836 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed rebuttal testimony on behalf the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gaslight & Coke Company (Peoples Gas) in Docket 17-0137.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan reconciliation case No. U-20554.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2020-2021 GCR plan reconciliation case No. U-20552.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR plan reconciliation case No. U-20236.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Ameren Illinois Company (Ameren) in Docket 20-0323.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan case No. U-20822.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 power plant and tree trimming securitization costs in case No. U-21015

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.

Experience and Qualifications of Sebastian Coppola

- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including

sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2017-2018 GCR Reconciliation case U-20078.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.

Experience and Qualifications of Sebastian Coppola

- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 gas general rate case U-18124 on a several issues, including

revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.

- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CECo Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CECo Gas Choice and End-User Transportation tariff changes case U-17900.
- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company’s 2015 general rate case on operation and maintenance costs in Docket 15-0142.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.
- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR plan case U-17317.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CECo's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in

Experience and Qualifications of Sebastian Coppola

Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CECo's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.
- Filed testimony in MichCon's 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors' compensation in the 2012 Avista general rate case.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio's power supply restructuring case in June 2012.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation's 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo's electric business Pilot Revenue Decoupling Mechanism in case U-16566.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.

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- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.
- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.

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- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the "Massachusetts Formula" at MichCon and at SEMCO in 1975 and 2000.
- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.
- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

EDUCATIONAL BACKGROUND

Experience and Qualifications of Sebastian Coppola

Mr. Coppola did his undergraduate work at Wayne State University, where he received the Bachelor of Science degree in Accounting in 1974. He later returned to Wayne State University to obtain his Master of Business Administration degree with major in Finance in 1980.

Corporate Analytics

DTE Presentation to Investors – February 17, 2026 Select Pages -

DTE

2025 Year-end Earnings Conference Call

February 17, 2026

Continuing to deliver exceptional results for our stakeholders; well positioned for long-term growth

- ✓ *Highly engaged team committed to delivering best-in-class results for our customers, communities and investors*
- ✓ *2025 operating EPS[1] of $7.36 is above the high end of guidance driven by strong performance at our non-utilities*
- ✓ *Executed 1.4 GW data center agreement with an additional ~3 GW in late-stage negotiations*
  - *Oracle data center project and continued need to modernize our utility assets drives a $6.5 billion increase to our five-year capital investment plan*
- ✓ *Potential further upside to capital plan as discussions advance for additional data center opportunities*
  - *Discussions progressing well; expect to reach final terms with additional customer 1Q 2026*
- ✓ *2026 operating EPS guidance provides 6% - 8% growth over 2025 guidance midpoint; well positioned to achieve high end of the range due to RNG tax credits*
- ✓ *Long-term operating EPS growth rate target of 6% - 8% through 2030, with 2026 guidance midpoint as the base; confident we will reach the high end of the guidance range in each year driven by RNG tax credits and the flexibility they provide*

1. Refer to the appendix for information regarding the reconciliation of operating earnings (non-GAAP) to reported earnings

2025 operating earnings[1] variance

(millions, except EPS)

	2024	2025	Variance	Primary drivers
DTE Electric	$1,105	$1,217	$112	Rate implementation, warmer weather, lower storm expense and higher renewable earnings partially offset by higher O&M and rate base costs
DTE Gas	263	295	32	Colder weather and rate implementation partially offset by higher O&M and rate base costs
DTE Vantage	133	162	29	RNG production tax credits and higher customer energy solutions earnings partially offset by lower investment tax credits and lower steel related earnings
Energy Trading	100	114	14	Continued strength in contracted physical power and gas portfolios
Corporate & Other	(185)	(258)	(73)	Higher interest expense and other one-time tax items in 2025
DTE Energy	**$1,416**	**$1,530**	**$114**	
Operating EPS	**$6.83**	**$7.36**	**$0.53**	
Avg. Shares Outstanding	207	207		

Exceeded the high end of operating EPS guidance range of $7.09 - $7.23 in 2025 driven by strong performance at our non-utilities

1. Refer to the appendix for information regarding the reconciliation of operating earnings (non-GAAP) to reported earnings

2026 operating EPS[1] guidance midpoint provides 7% growth over 2025 original guidance midpoint; positioned to achieve high end

(millions, except EPS)

	2026 operating earnings
DTE Electric	$1,340 - $1,360
DTE Gas	315 - 325
DTE Vantage	180 - 190
Energy Trading	50 - 60
Corporate & Other	(310) - (300)
DTE operating earnings guidance	$1,585 - $1,615
DTE operating EPS guidance	$7.59 - $7.73

- Utility growth driven by customer-focused investment supporting building the grid of the future and cleaner energy transition
- DTE Vantage guidance supported by new project development in the custom energy solutions space and production tax credit opportunities
- Continued strength in contracted physical power and gas portfolios at Energy Trading

Positioned to achieve high end of operating EPS guidance in 2026 due to favorability from RNG tax credits at DTE Vantage

1. Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix

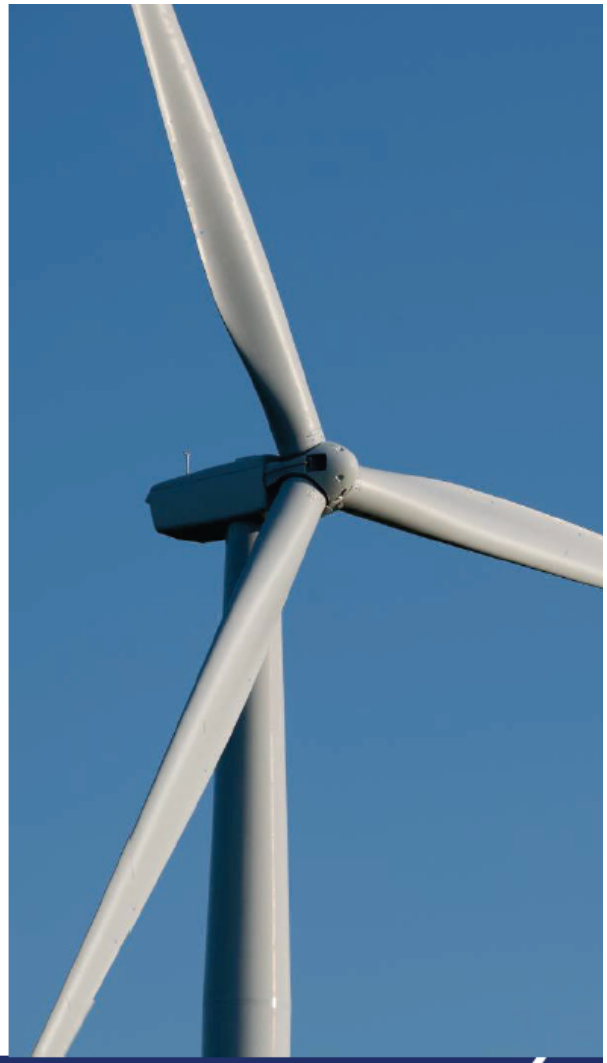
Maintaining strong cash flows, balance sheet and credit profile

Strong balance sheet supports robust customer-focused investment agenda

- Customer-focused capital investment plan is supported by consistent, healthy cash flows
- Targeting equity issuances of $500 - $600 million annually 2026 – 2028, with similar levels planned through 2030
  - The equity need is due to a ~$3.5 billion increase in capital over the next 3 years to support data center load growth and generation investments
  - Plan may also include additional junior subordinated debt to support balance sheet metrics
- Effectively managing debt maturities to support long-term plan
- Maintaining solid investment-grade credit ratings; targeting ~15% FFO / Debt[1]

Credit ratings	S&P	Moody's	Fitch
DTE Energy (unsecured)	BBB	Baa2	BBB
DTE Electric (secured)	A	Aa3	A+
DTE Gas (secured)	A	A1	A

1. Funds from Operations (FFO) is calculated using operating earnings, debt excludes a portion of DTE Gas' short-term debt and considers 50% of the junior subordinated notes as equity



Well positioned to continue to drive long-term value for shareholders while delivering affordable, reliable energy for our customers

Consistent Financial Results

- Met or exceeded operating EPS[1] guidance 18 of past 19 years
- Strong balance sheet and credit metrics support the execution of our long-term plan

Reliable and Affordable Energy for our Customers

- Executing on significant improvement in system reliability
- On track with goal to reduce power outages by 30% and cut outage time in half by 2029
- Continuous improvement culture drives success in maintaining affordability
- Residential electric bill increase well below national average since 2021

Solid Regulatory Construct

- Work collaboratively with the MPSC to ensure safe, reliable and affordable energy for our customers
- Renewable investments supported by cost recovery mechanism defined by Michigan energy law
- IRMs drive consistent, predictable infrastructure investments with timely recovery
- 10-month rate case cycle and forward test-year help reduce regulatory lag
- Transparent IRP process provides opportunity to align with key stakeholders on generation investments

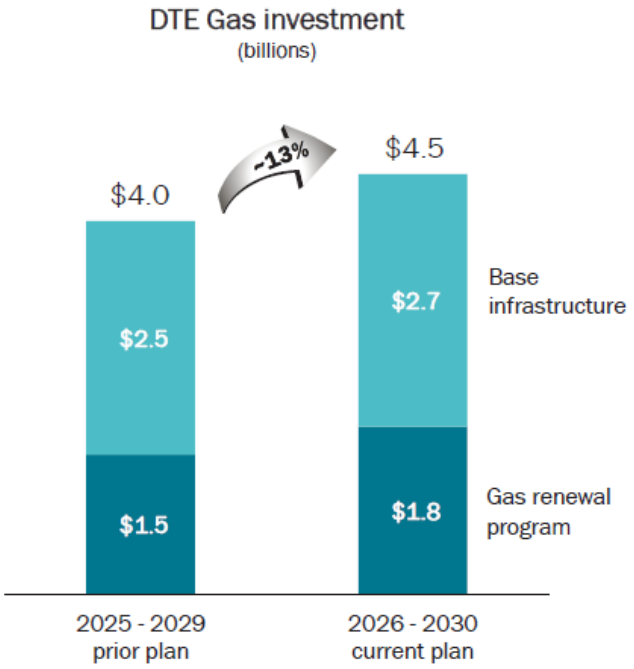
Strong Long-Term Growth Opportunities

- $36.5 billion five-year capital plan supports Oracle data center development, cleaner generation transformation and improved reliability
- Long-term operating EPS growth rate target of 6% - 8% through 2030; confident we will reach the high end of the guidance range in each year driven by RNG tax credits
- Confident that additional data center opportunities provide upside to long-term plan

1. Refer to the appendix for information regarding the reconciliation of operating earnings (non-GAAP) to reported earnings

DTE Gas: replacing aging infrastructure to ensure reliability and safety for our customers

- Continuing to improve customer service excellence and progress on main renewal
  - Ongoing progress on main renewal program; renewed ~2,000 miles since program inception
- Long-term capital investment plan focused on infrastructure improvements including main renewal investments to minimize leaks and reduce costs for our customers
  - Significant investment to support main renewal recovered through Infrastructure Recovery Mechanism (IRM)
  - Base infrastructure investments enhance distribution, transmission, compression and storage
  - Continued focus on safety and affordability for customers



MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-1.4a
Respondent: T. M. Uzenski
Page: 1 of 1

Question: Refer to Exhibit A-13, Schedule C12, and the CPI inflation rates on line 10 of 2.74% (2025), 2.40% (2026) and 2.3% (2027) from the S&P Global Market Intelligence – U.S. Economic Outlook of July 2025. Please:

a. Provide a copy of the July 2025 S&P report noted above.

Answer: Refer to page 4 of attachment.

Attachment: U-21973 AGDG-1.4a – S&PGlobal_Executive_Summary_2025_07

S&P Global
Market Intelligence

US Economic Outlook
July 2025

Executive Summary

To learn more or to request a demo, visit www.spglobal.com/marketintelligence.

Forecast at a glance

Base forecast (July 2025) 2025:Q2 - 2029:Q4

Major economic indicators

	% ch. from prior quarter, annual rate						% ch. from prior year, or annual average						% ch. from fourth quarter of prior year, or fourth-quarter average					
	2024.4	2025.1	2025.2	2025.3	2025.4	2026.1	2024	2025	2026	2027	2028	2029	2024.4	2025.4	2026.4	2027.4	2028.4	2029.4
Key indicators of real activity																		
Real gross domestic product	2.4	-0.5	1.3	1.2	1.8	2.2	2.8	1.4	2.0	1.7	1.6	1.7	2.5	0.9	2.1	1.5	1.7	1.7
Contributions to growth (% points):																		
Final sales to domestic purchasers	3.0	1.5	0.6	-0.4	0.7	1.4	3.1	1.7	1.1	1.6	1.8	2.0	3.1	0.6	1.5	1.7	1.9	1.9
Net exports of goods & services	0.3	-4.6	4.2	-0.1	0.8	0.8	-0.4	-0.4	0.7	0.1	-0.2	-0.2	-0.4	0.1	0.5	-0.1	-0.2	-0.2
Change in private inventories	-0.8	2.6	-3.5	1.7	0.4	0.1	0.1	0.1	0.2	0.0	-0.1	0.0	-0.2	0.3	0.1	-0.1	0.0	0.0
Major components of real GDP																		
Personal consumption expend.	4.0	0.5	1.5	0.8	1.5	2.3	2.8	2.0	1.9	2.2	2.4	2.4	3.1	1.1	2.2	2.3	2.5	2.4
Nonres. fixed investment	-3.0	10.3	-1.1	-4.8	-2.2	-1.6	3.6	1.7	-1.1	0.6	1.1	1.9	2.3	0.4	0.3	0.6	1.5	2.1
Residential investment	5.5	-1.3	-5.2	-6.0	3.4	0.9	4.2	-1.6	0.0	0.8	1.3	2.3	2.8	-2.3	0.8	1.0	1.9	1.7
Change in private inventories *	8.9	160.5	-42.7	59.4	80.1	84.9	39.0	64.3	103.7	100.7	88.0	84.1	8.9	80.1	113.8	92.6	85.0	82.6
Exports of goods & services	-0.2	0.4	-2.4	-2.8	1.9	4.0	3.3	0.6	3.1	4.4	3.5	3.2	3.0	-0.8	5.3	3.7	3.5	2.9
Imports of goods & services	-1.9	37.9	-26.6	-1.3	-4.1	-2.8	5.3	3.3	-2.9	3.0	4.4	4.5	5.5	-1.1	0.7	3.8	4.5	4.3
Gov't consump. & gross invest.	3.1	-0.6	-0.1	-0.5	-1.0	0.0	3.4	1.1	-0.2	-0.1	-0.2	-0.2	3.2	-0.5	0.0	-0.2	-0.2	-0.2
Pvt. housing starts (thous. units)	1387	1401	1318	1327	1326	1310	1371	1343	1306	1297	1301	1304	1387	1326	1304	1294	1307	1302
Light vehicle sales (mil. units)	16.5	16.4	16.1	15.0	14.6	14.6	15.8	15.5	15.0	15.6	15.8	16.1	16.5	14.6	15.4	15.7	15.9	16.1
Industrial production, total	-1.2	4.6	0.0	-0.4	-1.4	-0.8	-0.3	0.9	-0.5	-0.1	0.1	0.7	-0.3	0.7	-0.2	-0.2	0.4	0.7
Industrial production, mfg	-1.7	3.9	1.1	-0.3	-0.5	-0.3	-0.5	0.8	0.0	0.1	0.0	0.6	-0.5	1.0	0.3	-0.2	0.3	0.7
Capacity utilization (mfg, %)	76.2	76.7	76.7	76.4	76.0	75.7	76.8	76.4	75.5	74.7	73.9	73.7	76.2	76.0	75.3	74.3	73.8	73.6
Nonfarm payroll employ. (mil.)	158.6	159.2	159.6	159.8	159.9	160.0	158.0	159.6	160.2	160.6	161.0	161.7	158.6	159.9	160.4	160.7	161.2	162.0
Average monthly chg. (thous.)	209	111	150	62	-3	42	168	80	45	27	41	63	209	-3	51	23	54	59
Private nonfarm hours	0.8	1.3	2.7	0.2	0.3	0.0	0.2	1.2	0.3	0.0	0.1	0.4	0.6	1.1	0.1	0.0	0.2	0.4
Civilian unemployment rate (%)	4.2	4.1	4.2	4.3	4.4	4.5	4.0	4.2	4.5	4.6	4.5	4.3	4.2	4.4	4.6	4.6	4.5	4.3
Prices, Productivity, & Costs																		
CPI, all items, all urban	3.0	3.8	1.8	3.1	2.3	2.3	3.0	2.7	2.4	2.3	2.1	2.1	2.7	2.8	2.4	2.2	2.1	2.1
CPI excl food & energy, all urban	3.4	3.5	2.3	3.7	3.4	2.7	3.4	3.1	2.7	2.1	2.2	2.1	3.3	3.2	2.3	2.1	2.1	2.2
PCE price index	2.4	3.7	2.2	4.4	2.7	2.3	2.5	2.8	2.5	1.9	1.9	1.9	2.5	3.2	2.1	1.9	1.9	1.9
PCE price excl food & energy	2.6	3.5	2.7	4.9	3.1	2.5	2.8	3.1	2.7	1.8	1.9	1.9	2.8	3.6	2.1	1.8	1.9	1.9
PPI finished goods	3.0	4.3	-1.8	2.9	0.9	0.9	1.2	1.8	0.7	1.7	1.8	1.4	1.8	1.6	0.7	2.0	1.5	1.6
Compensation per hour	5.5	5.0	3.8	4.0	4.2	5.0	5.2	4.0	4.0	3.9	4.1	3.5	4.4	4.2	3.8	4.1	3.9	3.5
Output per hour	1.7	-1.8	-1.7	1.2	1.9	2.6	2.7	0.3	2.0	1.8	1.7	1.6	2.1	-0.1	2.3	1.7	1.7	1.5
Unit labor cost	3.8	6.9	5.6	2.8	2.2	2.4	2.4	3.7	2.0	2.1	2.3	1.9	2.3	4.4	1.4	2.4	2.1	1.9
Fed Financial Accounts HPI **	0.6	-1.3	-0.1	-0.2	0.0	0.2	8.1	-0.2	0.6	2.5	4.0	4.9	6.9	-1.6	1.4	3.2	4.4	5.1
Price of WTI crude oil ($/barrel)	70.74	71.78	64.44	63.78	55.23	51.57	76.48	63.81	54.32	64.37	68.79	72.13	70.74	55.23	57.60	67.19	69.87	73.80
Price of Brent crude oil ($/barrel)	74.53	75.80	67.64	68.00	59.67	55.50	80.50	67.78	57.92	68.59	72.66	75.82	74.53	59.67	61.00	71.43	73.60	77.50
Selected Financial Variables																		
Federal funds rate (%)	4.65	4.33	4.35	4.35	4.30	3.90	5.14	4.33	3.47	2.87	2.92	3.13	4.65	4.30	3.07	2.87	3.06	3.13
Yield on 10-Yr Treasury Notes (%)	4.28	4.45	4.36	4.33	4.24	4.12	4.21	4.35	4.02	3.88	3.90	3.94	4.28	4.24	3.93	3.87	3.92	3.95
Baa corporate bond yield (%)	5.82	6.06	6.29	6.32	6.29	6.26	5.81	6.24	6.24	6.20	6.14	6.08	5.82	6.29	6.23	6.17	6.12	6.07
Broad trade-wtd US$ (Jan 2006=100)	126.1	127.9	122.8	121.3	120.9	120.7	123.2	123.2	120.7	120.4	120.7	121.3	126.1	120.9	120.7	120.4	121.0	121.4
S&P 500 stock index, period end	5882	5612	6205	6010	5868	5780	5882	5868	5548	5439	5446	5477	5882	5868	5548	5439	5446	5477
S&P 500 stock index, average	5911	5901	5737	6108	5939	5824	5427	5921	5693	5457	5447	5459	5911	5939	5565	5433	5445	5469
Incomes & Related Measures																		
Corporate profits w/ IVA & CCAdj	23.3	-8.7	-12.6	-2.4	0.5	6.0	7.9	-0.5	2.4	1.0	0.7	3.0	6.9	-6.0	4.8	-0.3	1.7	3.3
Real disposable personal income	2.5	2.5	2.4	-0.8	1.3	8.9	2.7	1.6	3.7	3.2	2.8	2.7	2.3	1.3	4.5	3.1	2.8	2.6
Personal saving rate (%)	3.8	4.3	4.5	4.1	4.1	5.6	4.6	4.3	5.9	6.9	7.3	7.5	3.8	4.1	6.3	7.0	7.4	7.6
Fed. surplus (unified, FY, bil. $)	-2844	-2385	-721	-1576	-1877	-2670	-1832	-1881	-1842	-2094	-2366	-2227	-2844	-1877	-2325	-2615	-2477	-2730

* billions of chained 2017 $

** % change, not annualized, HPI = house price index

Source: S&P Global Market Intelligence

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.136a_Supplemental

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to Table 2 and lines 12-21 on page 10 of Ms. Jackson's direct testimony on Unplanned Main Renewals. Please:

a. Expand Table 2 to include actual information for 2025 and provide it in Excel.

Answer: Please see attached file U-21973 AGDG-4.*136 & 4.137 Unplanned Main Renewal* for requested information.

Attachment: U-21973 AGDG-4.136 & 4.137 Unplanned Main Renewal

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.137a_Supplemental

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to lines 2-12 on page 11 of Ms. Jackson's direct testimony on Unplanned Main Renewals. Please:

a. Explain and show how the forecasted number of units and unit costs for 2026 and 2027 were determined, in Excel.

Answer: Please see attached file U-21973 AGDG-4.*136 & 4.137 Unplanned Main Renewal* for requested information.

Attachment: U-21973 AGDG-4.136 & 4.137 Unplanned Main Renewal

U-21973 AGDG-4.136 &4.137 Unplanned Main Renewal

SEMI

Unplanned Main Renewal	2022	2023	2024	2025 P	2025 A	2026 P	2027 P
Capital Spend ($000)	$ 5,201	$ 4,391	$ 6,212	$ 8,500	$ 1,756	$ 3,500	$ 3,500
Units (feet)	15,002	14,489	15,700	18,100	8,479	10,044	10,044
Cost / Unit	$ 347	$ 303	$ 396	$ 470	$ 207	$ 348	$ 348

GRMI

Unplanned Main Renewal	2022	2023	2024	2025 P	2025 A	2026 P	2027 P
Capital Spend ($000)	$ 1,417	$ 1,427	$ 1,032	$ 2,277	$ 1,417	$ 2,277	$ 1,921
Units (feet)	12,407	9,349	7,627	14,164	8,290	17,227	15,528
Cost / Unit	$ 114	$ 153	$ 135	$ 161	$ 171	$ 132	$ 124

State

Unplanned Main Renewal	2022	2023	2024	2025 P	2025 A	2026 P	2027 P
Capital Spend ($000)	$ 6,618	$ 5,818	$ 7,244	$ 10,777	$ 3,173	$ 5,777	$ 5,421
Units (feet)	27,409	23,838	23,327	32,264	16,769	27,271	25,572
Cost / Unit	$ 241	$ 244	$ 311	$ 334	$ 189	$ 212	$ 212

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.139a_Supplemental

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to lines 14-25 on page 12 of Ms. Jackson's direct testimony on Public Improvements. Please:

a. Provide the actual capital expenditures for 2022 to 2025 and forecasted for 2026, 2027, 9 months ended 9/30/26, and 12 months ended 12/30/27, excluding the East Jefferson project, in Excel.

Answer: Please reference the attached file U-21973 AGDG-4.139 Public Improvement Project List for the requested information.

Projected Public Improvement capital expenditures, for 9 months ended 9/30/26 and 12 months ended 12/30/27 already exclude the East Jefferson project.

Attachment: U-21973 AGDG-4.139 Public Improvement Project List

Michigan Public Service Commission					
DTE Gas Company					
DTE Gas Detailed Routine Capital Project List for 2022 - 2025					
($000)					
Description	12 mos. ending 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	
Public Improvements	28,686	29,483	27,875	20,999	

Exhibit AG-5

CONFIDENTIAL

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.146a_Supplemental

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 24 and 25 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

a. Provide the number of units of each type of meter and communication/controls for each year 2022 to 2025 and forecasted for 2026 and 2027 with related dollars in Excel.

Answer: Please reference the attached file for the requested information.

Attachment: U-21973 AGDG-4.146a Comms & Controls Meter Purchases

U-21973 AGDG-4.146a

		Actual								Forecast			
		2022		2023		2024		2025		2026		2027	
Material Description	**Meter Type**	**Units**	**$'s (000s)**	**Units**	**$'s (000s)**	**Units**	**$'s (000s)**	**Units**	**$'s (000s)**	**Units**	**$'s (000s)**	**Units**	**$'s (000s)**
Diaphragm AC 250 AMER, 402 TMS	Diaphragm	24,880	$ 2,803	50,020	$ 5,139	28,862	$ 3,144	20,000	$ 2,382	20,000	$ 2,551	10,000	$ 1,238
Diaphragm AC 250 AMER, 405 TMS	Diaphragm			17,999	$ 1,758	1,860	$ 195	-					
Diaphragm AL 425 AMER, 403 TMS	Diaphragm	8,770	$ 2,287	11,532	$ 2,952	3,640	$ 1,535	10	$ 4	1,800	$ 564	700	$ 213
Diaphragm 800 AMER, 404 TMS	Diaphragm	638	$ 510	1,650	$ 1,562	810	$ 841						
Rotary Meters	Rotary	1,474	$ 2,279	1,620	$ 2,419	1,460	$ 2,441	4,079	$ 6,276	2,623	$ 5,282	3,224	$ 6,739
Ultrasonic Meters	Ultrasonic									7,500	$ 2,070	21,000	$ 5,794
By-Pass Devices	By-Pass									7,500	$ 1,125	21,000	$ 3,150
Modules	AMI/AMR Modules	20,968	$ 1,159	60,932	$ 3,485	78,042	$ 5,004	47,793	$ 4,002	63,400	$ 4,711	45,200	$ 3,324
Indirects, Overheads, & Misc. Costs			$ 991		$ 1,562		$ 1,672		$ 1,617		$ 1,612		$ 2,023
Total - Purchase Meters		**56,730**	**$ 10,030**	**143,753**	**$ 18,877**	**114,674**	**$ 14,832**	**71,882**	**$ 14,281**	**102,823**	**$ 17,916**	**101,124**	**$ 22,482**
Intest			$ 4,371		$ 4,621		$ 4,545		$ 4,170		$ 4,523		$ 4,523
Total Communications & Control Meters			**$ 14,401**		**$ 23,498**		**$ 19,378**		**$ 18,451**		**$ 22,438**		**$ 27,005**

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.146b

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 24 and 25 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

b. Explain what work the Company can perform with the by-pass device while gas continues to flow into the building,

Answer: When installed, the Company will be able to perform a meter change on an outside meter without interrupting gas and scheduling an appointment with the customer. As mentioned in direct testimony by Witness Jackson, page 29, lines 6-9, "This eliminates the need to shut off gas to the customer during routine or emergency work, thereby preserving service continuity for the customer and subsequently eliminating the need for customer appointments in order to relight appliances inside the customer's home." The by-pass device will save the customer the inconvenience of having to be on-site for an outside meter change to be performed, allowing the customer to have an uninterrupted day that may require them to reschedule other appointments or take days off of work. The by-pass device will also reduce field cannot get in visits.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.147b
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to Tables 5 and 6, and lines 14-19, on page 25 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

b. Explain on what basis and evidence the Company expects diaphragm meters will begin to fail in large number by 2030.

Answer: In Witness Jackson's testimony, page 26, Q&A 55, the Company has identified that the AMI and AMR modules currently attached to the diaphragm meters will begin to fail in large volumes by 2030. The Company started installing these modules in 2008 on existing diaphragm meters and continued to install the modules on meters through 2023 to reduce manual reads. ITRON modules have a forecasted life of 20 years. However, the Company is experiencing modules failures at approximately 17 years. By 2030, the Company expects approximately 100,000 module failures to occur in that year. In the years 2030 through 2038 the Company is anticipating an average of 115,000 to fail each year. The average age of the Company's diaphragm meters in 2030 will be 35 years. Once a meter hits 35-40 years of age, meters begin to fall out of the accuracy tolerance (+/- 2%).

Year	Estimated Battery Failures
2026	~3,000
2027	~4,000
2028	~5,000
2029	~35,000
2030	~110,000
2031	~146,000
2032	~153,000
2033	~124,000
2034	~61,000
2035	~66,000

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.148a
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to page 27 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

a. Provide evidence that the industry is shifting toward ultrasonic meters with integrated cellular communication and identify what percentage of gas utilities in the U.S. have shifted the majority of their meters to ultrasonic meters.

Answer: Manufacturers, while still producing diaphragm meters, are indicating a switch to ultrasonic meters. For example, in 2020 ITRON discontinued manufacturing diaphragm meters to focus on ultrasonic meters, Honeywell is projecting 400k ultrasonic meter capacity by end of 2026 and is planning to scale production to 1 million units in 2027. When Honeywell ramps up its production of ultrasonic meters in 2027, they will be producing the same number of ultrasonic meters as their diaphragm meters annually. This is a significant signal of the industry shifting toward ultrasonic meters, especially since it aligns with their mass-production capability for diaphragm meters.

Gas utilities are increasingly moving toward residential ultrasonic meters rather than traditional diaphragm meters. Evidence of this shift includes publication of the ANSI B109.6-2024 dedicated North American standard for single-path ultrasonic gas meters under 1,400 CFH, reflecting broad industry adoption and standardization. Large utilities have already transitioned to residential ultrasonic metering at scale. For example, CenterPoint Energy, Spire, and Peoples Gas have each deployed ultrasonic gas meters in quantities ranging from approximately 700,000 to over 1 million meters, demonstrating that ultrasonic technology is no longer experimental, but a mature, industry standard of measurement for residential sites. The scale of these implementations demonstrates that ultrasonic residential metering has become the prevailing replacement technology for aging diaphragm and AMI/AMR meter populations.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.149

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to page 28 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please provide a copy of the cost/benefit analysis with net present value calculations in Excel showing that the shift to ultrasonic meters is economically beneficial.

Answer: Please reference the Company's response to audit request HH-4.1.

Attachment: None

MPSC Case No: U-21973
Requester: Staff
Question No.: HH-4.1
Respondent: A. E. Jackson
Page: 1 of 1

Question: Has the Company performed a cost-benefit analysis or any similar analysis for the proposed ultrasonic meter project? If so, provide it.

Answer: As stated on page 27 of Witness Jackson's direct testimony, if the Company were to retain its existing diaphragm meters while replacing only the AMI/AMR modules, it would continue investing in technology that is quickly becoming obsolete. This would require continued maintenance of an aging system that is becoming harder to support due to limited manufacturer availability.

The Company must replace its aging modules and its aging diaphragm meters. For the initial investment included in U-21973, the Company ran a customer impact analysis which resulted in a ~$0.3 per month bill impact in 2030 for the ultrasonic meter and by-pass device capital expenditures. As discussed in Witness Jackson's direct testimony, page 30, lines 6-19, ultrasonic meters represent the best solution for the cost impact for our customers, and as discussed in Witness Jackson's direct testimony page 28, lines 14-19, bring additional safety features.

To complete a comprehensive long-term cost-benefit analysis, as stated in Witness Jackson's direct testimony, Q56, page 27, "We also need to determine how the new technology performs on a larger scale in the field and potential benefits before replacement of gaining infrastructure accelerate in the future." The Company will use the investment proposed in the instant case to gain that data and bring back a full program recommendation on pace, duration and cost benefit impact to address the full population of meters.

If the Company does not install Ultrasonic meters, any safety benefits that could be realized from these meters in the form of quicker action in emergency scenarios cannot materialize. Diaphragm meters do not offer these features.

Attachment: None.

MPSC Case No: U-21973
Requester: Staff
Question No.: HH-1.3c
Respondent: A. E. Jackson
Page: 1 of 2

Question: Regarding the ultrasonic meters described by Witness Jackson,

c. Provide a complete list of benefits of the ultrasonic meters. Quantify the benefits whenever possible.

Answer: If the Company were to retain its existing diaphragm meters while replacing only the AMI/AMR modules, it would continue investing in technology that is quickly becoming obsolete. This would require continued maintenance of an aging system that is becoming harder to support due to limited manufacturer availability. Eventually, the Company would still need to replace the diaphragm meters, but doing so at a later date would result in higher costs as we duplicate replacement efforts of meters and modules that have already had AMR/AMI replacement. By addressing both the AMR/AMI modules and aging diaphragm meters with the installation of a single ultrasonic meter, the Company can proactively address this aging infrastructure, supporting a more efficient transition to a modernized metering system. The Company needs to install enough of these meters to understand and operationalize the performance of these features on a large scale over several years to be able to reliably act on the data they provide. Some additional future benefits are listed below. The benefits will gradually be realized as the installation of the ultrasonic meters and by-pass devices progresses.

Quantifiable Benefits	Estimated Potential Future Savings[1]
• Eliminates gas service interruption during routine meter work, reducing the need for customer appointments	~$2.0M - $2.5M
• Reduction of meter reading costs	~$1.5M - $2.0M

MPSC Case No: U-21973

Requester: Staff

Question No.: HH-1.3c

Respondent: A. E. Jackson

Page: 2 of 2

Other Benefits

- Monitoring of pressure, flow, and temperature for potential future alarming / auto shut-off
- Mandatory leak checks that are time-stamped which enable automatic meter connectivity
- Ultrasonic meters support higher delivery capacity, which reduced the amount of customers requesting upgrades from 402 to 403 meters
- Eliminates Does Not Register (DR) meters for diaphragm meters
- Two-way communication with meter for automatic program updates, meter reading frequency
- Improved meter accuracy due to less mechanical moving parts

1. Estimated Potential savings if and when all meters are converted to ultrasonic technology. These will not be realized based on the proposed installations in 2026 and 2027.

Attachment: None.

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.150a

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 29 and 30 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

a. State whether the Company currently performs outside or inside the building meter replacements without a customer appointment and whether it would do so in the future with ultrasonic meters.

Answer: The Company currently requires an appointment to perform a meter change, except for in an emergency situation such as a leak call. As part of the diaphragm to ultrasonic meter replacement project, the Company will be installing a bypass device on outside meters. Once a bypass is installed there will no longer be a need for an appointment for outside meter changes or repairs. An appointment will still be required for inside meter changes or repairs. Our initial roll-out includes GRP work where meters are moving outside.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.150b

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 29 and 30 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

b. Please identify the peer utilities contacted and identify what successes and problems they have had with ultrasonic meters installed for a majority of their customers and how many years those meters have been in place.

Answer: Peer utilities contacted include NiSource, Liberty, Spire, Southwest Gas and Duke. Spire shared that they have 1 million ultrasonic meters installed, their installations began in 2023. NiSource and Duke are starting ultrasonic meter installations this year, 2026. None of the utilities we contacted identified any major issues.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.150c

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 29 and 30 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

c. Provide the year that the Company completed the installation of the current AMI and AMR meters.

Answer: The initial AMI and AMR project, started in 2008, to install automated read modules on existing diaphragm meters was completed in 2023 as 98% of all meters installed were equipped with Advanced Metering capabilities. The Company continued some AMI/AMR installations throughout 2024 and 2025 to install AMI/AMR devices on some additional meters that did not have a module. As part of normal business practice since the project began, every new residential meter that the Company installs is equipped with an AMI or AMR module, unless the customer requests otherwise.

The Company will continue to install diaphragm meters with AMI and AMR modules as the installation of ultrasonic meters ramps up, as discussed in Witness Jackson's direct testimony page 31, line 23. The ramp up starts in the Company's Southeast Michigan territory late 2026.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.150e

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 29 and 30 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

e. Confirm that the ultrasonic meters would replace the Itron AMI and AMR meters and the Company would operate three separate meter communications systems for multiple years. Provide the expected transition years.

Answer: Yes, the ultrasonic meters would be used in place of the Honeywell diaphragm meter with an ITRON AMI or AMR module attached. What is proposed in this case is an initial roll out. The Company will be utilizing three methods for collecting reads, AMI reads, AMR reads and Ultrasonic reads. The full transition is to be determined. As stated in Witness Jackson's direct testimony, page 30, lines 23-25 and page 31, lines 1-2, "The Company plans to begin installing the new Ultrasonic Meter Technology and by-pass device in late 2026 and slowly ramp up in the following years to get enough meters in the field to better understand the new features and benefits. The initial installs will be prioritized through integration with existing operational programs, including routine meter work and the Gas Renewal Program (GRP)." Whether the Company pursued ultrasonic meters or new AMI modules to replace the aging ITRON 2.4GZ AMI module, a third communication system would be required. We are one of only two companies that currently use the ITRON 2.4 GZ.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.150f
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to pages 29 and 30 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

f. Identify the number of years that the ultrasonic meters the Company plans to install have been in use at customers' premises at other gas utilities. Provide the known reliability and failure rate of this type of ultrasonic meters, and related communication system, their accuracy, and actual performance results.

Answer: Ultrasonic meters offer tangible advantages over legacy diaphragm meters. Ultrasonic meters contain no moving parts, which significantly improves long-term accuracy and stability and reduces performance degradation over time. This results in more accurate billing. Additionally, ultrasonic meters provide advanced diagnostics that allow the Company to proactively monitor meter health, identify abnormal operating conditions, and manage assets based on condition rather than the age of the meter. For the Company to purchase a meter to be deployed in the field, the meter must be +/- 1% accuracy. The average accuracy of ultrasonic meters is within .17% accuracy vs diaphragm meters is .9% accuracy. A difference between 0.17% and 0.9% may sound small, but across thousands of cubic feet of gas per year, it can significantly affect billing accuracy, leak detection, and system efficiency.

Cellular communication provides greater reliability, broader coverage, and faster access to meter data than legacy AMI/AMR systems, while avoiding the need for the Company to own and maintain extensive communications infrastructure. By leveraging commercial carrier networks, cellular systems reduce missed reads, improve operational efficiency, and lower long-term technology and infrastructure risk for customers. We have seen an example utility with over 700k cellular meters installed and a read rate of 99%.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.150h

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 29 and 30 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

h. Does the Company need to replace the communication network transmitting meter readings and other data to the Company, or can the existing communication network still be used? If a new network is needed, identify the cost and provide a reference in which exhibit and line number that cost is included.

Answer: The Company needs to add a method to receive cellular reads and other data. The IT information is discussed in Witness Bolda's direct testimony, page 49, lines 8- 25 and continued page 50 lines 1-9

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.150j
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to pages 29 and 30 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

j. Provide the total projected cost for the conversion to ultrasonic meters from inception to completion in Excel with the related number of units by year. Breakdown the cost among the various components: meters, communication systems, software, contractor labor, company labor, overheads, etc.

Answer: The Company is currently proposing an initial roll-out as discussed in Witness Jackson's direct testimony, page 25, lines 22-25 and page 26, lines 1-12. The Company needs to get the meters in the field before larger rollout. We have not identified a total project sensitive to performance cost. We will be using this initial rollout to gather information on meter and bypass performance in our territories, field installations and success and pain points. This initial rollout is targeted at aging modules and meters and being done through our GRP program and Routine work. The Company needs to do this initial installation to learn and understand success and failures before expansion of program. Please reference the response to HH-1.3afor a breakdown of proposed costs in this case.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.150l

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 29 and 30 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

l. Provide the cost of the bypass device and how many times/occurrences annually, once installed on all meters, the Company would expect to use this feature based on current experience.

Answer: The target cost of the bypass is estimated at $150 per unit. The life expectancy of the unit is ~60 years. If/when the bypass is rolled out to the entire population of meters, we would anticipate using this feature ~25k times annually. The bypass will preserve service continuity for the customer and subsequently eliminate the need for customer appointments in order to relight appliances inside the customer's home. This improves the customer experience as they no longer have to take time off work or other activities to be home for an appointment in these instances.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.150m

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 29 and 30 of Ms. Jackson's direct testimony on Communication and Control-Meters. Please:

m. Provide the cost savings per meter and in total for all meters to be eventually installed if this the bypass device was not installed.

Answer: The cost of the bypass is estimated at $150. Without the bypass installation, you lose the opportunity to support the customer experience of having uninterrupted service during outside meter change or repair and the convenience of the customer not having to be at home for this work to be done.

In benchmarking sessions with our peer Consumers Energy, we learned that they have are actively installing bypass devices on customer meter and have been doing so since 2020. This allows them to exchange a meter without interruption or need for relighting of appliances.

Attachment: None

Exhibit AG-7

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MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.168
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to Exhibit A-12, Schedule B5.11, page 1 on the Ford Lake Dam (line 4.7), the I-375 Russell Bidge (line 4.30), and the Ford Road Relocates (line 4.33) projects. For each project, please provide the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Answer: Ford Lake Dam project is currently in the engineering design phase. Contractor bids are actively being requested and construction start is anticipated to occur in May 2026 with a construction end date anticipated in November 2026.

I-375 Russell Bridge project is still in the preliminary assessment stage. The project planning and scoping phase will begin when MDOT provides their phased construction plan for this area.

Ford Road Relocates project was originally planned to be designed in 2026 and constructed in 2027,but changes in MDOTs construction schedule will now necessitate design in 2027 and construction in 2028 in coordination with MDOT in 2028. Public improvement projects move around in timing and schedule often. Historically, new projects have come in to replace projects with schedule changes such as Ford Road in 2027.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.169
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to Exhibit A-12, Schedule B5.11, page 4, on the projects on lines 8.155 to 8.157, 14.3, 14.4, 14.6, and 14.8. For each project, please provide the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Answer:

Line	Project Name	Phase	Planned Construction Start Date
8.155	Euclid 60 PSI Huber Main	Engineering Design	June 2027
8.156	McNichols & Greenfield	Engineering Design	May 2027
8.157	Glendale & Telegraph	Engineering Design	June 2026
14.3	Guthrie Lakes (PETCT)	Ready for Construction	July 2026
14.4	Coral/Cowden Lake (GRRSC)	Ready for Construction	March 2026
14.6	Honey Creek (GRRSC)	Ready for Construction	February 2026
14.8	Conklin (GRRSC)	Ready for Construction	March 2026

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-3.109b
Respondent: K. M. Fedele
Page: 1 of 1

Question: Refer to pages 42-43 of Ms. Fedele's direct testimony on the South Grand Rapids Pipeline project. Please:

b. Explain whether the Company has performed any direct assessment and laboratory analysis of the welded seam problem on this pipeline and describe the results of those assessments and lab analyses that support a replacement at this time.

Answer: While the pipeline has been exposed for construction activities, no direct assessment or laboratory analysis has been performed because the assessment of this pipeline is not due until 2029.

Regardless, we have performed lab analysis and ran ILI tools on pipelines with pipe of similar vintage manufactured by the same manufacturer, AO Smith. We have found defects on these pipelines consistent with what is known in the industry about the poor historical manufacturing processes of AO Smith pipe. This includes lack of fusion, seam cracks, selective seam corrosion, and laminations.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-3.109c
Respondent: K. M. Fedele
Page: 1 of 1

Question: Refer to pages 42-43 of Ms. Fedele's direct testimony on the South Grand Rapids Pipeline project. Please:

c. Provide the number of leaks experienced in each of the past five years 2021 to 2025 in this section of the pipeline.

Answer: There have been no known leaks on this pipeline in the last 5 years. However, the Company cannot wait for transmission leaks to occur before implementing preventive upgrades as transmission failures could be more catastrophic and the resulting consequences are more impactful, especially when compared to a leak on a low-pressure distribution system.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-3.111b
Respondent: K. M. Fedele
Page: 1 of 2

Question: Refer to page 45 of Ms. Fedele's direct testimony on the South Grand Rapids Pipeline project. Please:

b. Provide photos or other evidence of the wrinkle bends and explain their severity.

Answer: Wrinkle bends are known to create potential high-stress areas on the pipeline due to the creases or "wrinkles" that were formed during the construction phase that could lead to a rupture.

A Completion Report for this pipeline, dated December 28, 1949, describes the construction process in detail. This report notes that changes in direction were made by bending the pipe utilizing the cold wrinkle method and describes the specifications for the wrinkle bending.

In addition, there have been many failures in the industry with wrinkle bends being the root cause. For example, in 2010 when a 30" line ruptured in Louisiana due to a crack that developed around the circumference of a wrinkle bend and in 2009 when a 24" line ruptured in Alabama due to a failed wrinkle bend.

Below are sample photos of a wrinkle bend containing several individual wrinkles from the DTE system. The Company does not have such photos of the South Grand Rapids pipeline.

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-3.111b
Respondent: K. M. Fedele
Page: 2 of 2

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-8.347
Respondent: K. M. Fedele
Page: 1 of 1

Question: Refer to DR AGDG-3.109a on wrinkle bends in the Company's transmission pipelines. Please identify how many pipelines the Company has with wrinkle bends and how many have ruptured in the past 10 years.

Answer: Assuming the reference in the question is for AGDG-3.111b, there are 4 pipelines in our system with wrinkle bends and no ruptures have occurred in the past 10 years.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-8.348
Respondent: K. M. Fedele
Page: 1 of 1

Question: Refer to DR AGDG-3.110 on direct assessment of the condition of transmission pipelines. Please identify on how many occasions in the past three years the Company has performed direct assessments of transmission pipelines. Identify the pipelines, what the direct assessment entailed, and describe what the findings were.

Answer:

	# of Pipelines	Pipelines
2023	0	0
2024	5	Southern Gate Station, Munising 4", Casings, Traverse City Gate Station, Traverse City West Gate Station
2025	2	Northeast Gate, Willow Gate

Direct assessment was used to assess for external corrosion and internal corrosion only. There have been instances of both external and internal corrosion observed utilizing direct assessment; however, in all cases listed above, the pipeline segments were found in satisfactory condition without any repairs required.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-3.106

Respondent: K. M. Fedele

Page: 1 of 1

Question: Refer to page 31 of Ms. Fedele's direct testimony on the East Petoskey Pipeline and Taggart Compressor station projects having not received approval. Explain why no approval has been given and who needs to approve them.

Answer: The East Petoskey Pipeline Project has not received capital project approvals as it is still in the initial engineering phase, but it is anticipated to receive approval in Q2 of 2026.

The Taggart Compression Station Replacement Project received Company Executive and Board of Directors capital project approvals on December 3, 2025.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.155a
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to page 49 of Ms. Jackson's direct testimony on the Columbus 23 gas storage processing unit upgrade project. Please:

a. Provide the total projected cost for the upgrade from inception to completion in Excel.

Answer: Please reference Witness Jackson's direct testimony, page 49 lines 11-13, for the total cost of the Columbus 23 upgrade project discussed in this immediate case.

The first phase of the Columbus 23 upgrade project is intended to upgrade the well at Columbus, by plugging and replacing the currently existing well, as described in Witness Jackson's direct testimony, page 47 lines 18-25 and page 48 lines 3-17. Completion of the first phase of the Columbus 23 upgrade project will yield the benefits as described Witness Jackson's direct testimony, page 48 lines 20-25

The second phase of the Columbus 23 upgrade project is not planned to occur until after the end of the projected test year, September 2027, and will involve upgrading the processing equipment that separates the gas from oil and water that comes from the well.

The preliminary estimates for the total cost of the Columbus 23 upgrade is ~$6M in capital expenditures, but detailed estimates for the second phase are not yet available and will be discussed in a subsequent rate case proceeding after scoping has occurred

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.155d
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to page 49 of Ms. Jackson's direct testimony on the Columbus 23 gas storage processing unit upgrade project. Please:

d. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Answer: The Columbus 23 facility upgrade project is currently in the project planning and scoping phase. The next step is engineering design, which is expected to begin in Q2 of 2026.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.157c

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 53-54 of Ms. Jackson's direct testimony on the Belle River Mills Z#5 Engine and Compressor Overhaul project. Please:

c. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Answer: The Company is in the project planning and scoping phase of this project. The next phase is to obtain competitive contractor bids for material procurement, which is expected to occur in March of 2026 due to many of the materials having extensively long lead times.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.158d
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to pages 56-58 of Ms. Jackson's direct testimony on the Belle River Mills Unit 8 Turbine Engine Exchange project. Please:

d. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Answer: This project is currently in the planning and scoping phase.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.160a
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to pages 65-67 of Ms. Jackson's direct testimony on the NORC Expansion and Renovation project. Please:

a. Identify what the evolving training and operational needs are in Northen Michigan.

Answer: The training and operational needs in Northern Michigan have evolved due to a combination of workforce demographic changes and increased technical demands within the region's gas operations. A younger, less experienced workforce requires sustained, structured, and full-time instructional support to achieve and maintain competency in critical field activities. This need is intensified by higher MISS DIG volumes, seasonal work extensions, and an expanding set of regulatory expectations that necessitate consistent, high-quality training delivery rather than intermittent or part-time instruction.

Recent additions to the training curriculum in Northern Michigan reflect the growing technical complexity of field equipment, procedures, and new technologies deployed across the system. These classes have been introduced to ensure personnel can perform their duties safely, accurately, and in accordance with current operational standards. The expansion of training content is not discretionary but rather a response to evolving operational conditions, ensuring the workforce maintains the level of proficiency required to support safe and reliable service across the region.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.160b
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to pages 65-67 of Ms. Jackson's direct testimony on the NORC Expansion and Renovation project. Please:

b. Identify what the space constraints are and why they cannot be resolved with existing buildings and facilities in Northern Michigan and surrounding areas.

Answer: Current facilities in Northern Michigan are inadequate to support the scope and scale of modern training requirements, particularly given the need for dedicated environments to deliver specialized instruction, such as leak response and TSIM training, which will need dedicated space for larger props and overlapped classes. Existing buildings lack sufficient dedicated training areas and rely on shared spaces that must also accommodate construction activities, resulting in frequent disruptions, significant inefficiencies, and limitations on class size and availability. These operational conflicts impede the consistent delivery of technical instruction and reduce the effectiveness of the training programs.

The constrained physical layout of the existing facilities also restricts the use and storage of essential training props, increases setup and teardown time, and limits the Company's ability to offer additional refresher courses requested by field operations. Expanded appliance, boiler, and distribution new-hire training requires additional equipment and dedicated space that the current facilities cannot provide. Constructing new training space will eliminate unnecessary travel to downstate locations, improve training throughput, and support emerging technologies and workforce requirements. As a result, the limitations inherent in the current buildings cannot be feasibly resolved within their existing configurations. Modifications to the existing NORC cannot meet these combined requirements.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.160e
Respondent: A. E. Jackson
Page: 1 of 1

Question: Refer to pages 65-67 of Ms. Jackson's direct testimony on the NORC Expansion and Renovation project. Please:

e. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Answer: The project is currently in the project planning and scoping phase. Engineering design is planned to begin in April 2026.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.160f

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 65-67 of Ms. Jackson's direct testimony on the NORC Expansion and Renovation project. Please:

f. Provide the cost/benefit analysis with the net present value calculations in Excel showing the project is economically justified.

Answer: Existing space constraints made renovation of the current building infeasible. The expansion is the only option to accommodate both operations teams while simultaneously addressing the training needs as described in the Company's responses to AGDG-4.160a and AGDG-4.160b. Having a well-trained workforce is essential to delivering safe and reliable gas service to our customers in the Greater Michigan service territories. Therefore, this project was prioritized based on operational requirements.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.161a

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 67-69 of Ms. Jackson's direct testimony on the Michigan Ave. Service Center Renovation project. Please:

a. Identify what problems have been experienced at this service center in the past three years that require a major renovation.

Answer: Please reference the attached file U-21973 AGDG-161 Michigan Ave Service Requests inclusive of the service requests at Michigan Ave over the last three years.

Infrastructure is at end of life, particularly HVAC and plumbing. Multiple corrections have been performed to keep the systems running but a full replacement is needed. Over the past three years the Company has had multiple heating or cooling outages at the site. The Company has had leaks and failures with piping systems that have had spot repairs, and has required multiple repairs on fixtures in bathrooms & locker rooms.

Attachment: U-21973 AGDG-4.161 Michigan Ave Service Requests

TICKETI	SAFETYRELATE	DATE REPORTE	DESCRIPTION	LOCATIO	ASSIGNEDT
10973780		3/22/2023	Michigan Ave - Hydraulic leak (seep) coming from hose that dispenses AW32 hydraulic fluid. Garage. B	MICSC	FO_DWEST
10998951	Y	4/10/2023	Michigan Ave - Mold in garage upper office. some on floor and ceiling. - Loc Info: garage area. - Mi	MICSC	FO_DWEST
11048628	Y	5/8/2023	Mini split in Michigan ave garage office not work because needs to be wired up	MICSC	FO_DWEST
11145982		7/6/2023	Remove abandoned drainpipe from Michigan Ave Gas Warehouse. Contact for details	MICSC	FO_DWEST
11230347		8/25/2023	Michigan Ave - Air hose defects at North wall , near office and West wall. . Hydraulic hoses seeping	MICSC	FO_DWEST
11255641		9/11/2023	Michigan Ave Garage - Need to have a 20 amp plug installed upstairs for our hose cut off wheel. - Mi	MICSC	FO_DWEST
11623437		5/10/2024	Remove abandoned pipe in ceiling and racks in whse area for Supply Chain Group v	MICSC	FO_DWEST
11642640		5/21/2024	half of a Tree fell partially blocking driveway. Iconed it off to make safe. It	MICSC	FO_DWEST
11650179		5/23/2024	Michigan Ave - Lights over gas pumps flickering . - Tammie Tucker 734-544-7871	MICSC	FO_DWEST
11709115		6/22/2024	Michigan Ave - Ihave a water leak in the ceiling in my warehouse office. Ihave a can catching the	MICSC	FO_DWEST
11764355		7/24/2024	Michigan ve - Garage door is inoperative for bay number two. The chain is broken . Has fallen off th	MICSC	FO_DWEST
11800254		8/13/2024	Michigan Ave Garage Bay # 3 - Floor drain in Bay 3 is very slow to drain takes a few days. Michael M	MICSC	FO_DWEST
11802668		8/14/2024	Michigan Ave - Need heat turned off in warehouse and women's restroom. - Tammie Tucker 734 -544-7871	MICSC	FO_DWEST
11873746		9/23/2024	Michigan Ave- Garage bathrooms lights are not working. - Michael Machnak 313)897-0351	MICSC	FO_DWEST
11945483		11/1/2024	Michigan Ave - Filling of potholes and leveling of uneven surfaces in parking lot around roll-off bo	MICSC	FO_DWEST
11945523		11/1/2024	Warehouse metal railing sticking up along floor by rollup door needs to be remov	MICSC	FO_DWEST
11966171		11/14/2024	Michigan Ave - we have serval lights out in the Garage area. let me know if we can update this with	MICSC	FO_DWEST
11978012		11/21/2024	Michigan Ave - Bay door #2 is not fully closing in the Garage . Stops about 3 inches from the floor.	MICSC	FO_DWEST
11984287		11/27/2024	Michigan Ave - An electrical cord has damaged in our parking lot . Aisle # 10 . . Cord was severed .	MICSC	FO_DWEST
11985441		11/27/2024	Michigan Ave - Heat not working in the wash bay at Michigan Ave garage area. Michael Machnak 313-)89	MICSC	FO_DWEST
11990694		12/4/2024	Middle urinal in mens restroom is leaking at the top. - Tammie Tucker 734-544-7871	MICSC	FO_DWEST
12023255		1/2/2025	Michigan Ave * The air compressor in the Garage will not build aiGarage will not build air pressure.	MICSC	FO_DWEST
12049539		1/22/2025	Michigan Ave. Garage Bathroom . -The heat is not working in the garage bathroom . - James Michalik	MICSC	FO_DWEST
12058790		1/30/2025	Michigan Ave We need a replacement of the Warehouse overhead door remote control that goes in the f	MICSC	FO_DWEST
12064902		2/5/2025	Michigan Ave Heat still not working in the bathroom arear of the Michigan Ave garage . -Michael Mac	MICSC	FO_DWEST
12075371		2/17/2025	112430	MICSC	FO_DWEST
12085189		2/26/2025	Michigan Ave - Bathroom light not working on the sink in the garage bathroom Michael Machnak 313) 89	MICSC	FO_DWEST
12094318		3/5/2025	Mini split in Michigan Ave garage area is nor hooked up please look at hooking this unit up during t	MICSC	FO_DWEST
12142495		4/3/2025	Michigan Ave - Lights bulbs need replacing in Warehouse Office. - Keuth Littker 313.858-0250	MICSC	FO_DWEST
12204565		5/5/2025	Michigan Ave Garage - Air compressor has stopped compressor at Michigan Ave Garage stopped working.	MICSC	FO_DWEST
12263831		6/3/2025	Michigan Ave side overhead door will not close.Michael Machnak 313)897-0351	MICSC	FO_DWEST
12286076		6/13/2025	Michigan Ave - Garage door on bay 3 will not close its about 3 feet of the floor. - TTC - Caulk / s	MICSC	FO_DWEST
12309005		6/25/2025	Michigan Ave garage toilet not flushing. I recommend leaving a plunger if possible. Please make this	MICSC	FO_DWEST
12312506		6/27/2025	Michigan Ave - Air conditioning for Mich Ave Warehouse office is not working, - Keith Littler 313-85	MICSC	FO_DWEST
12312509		6/27/2025	Michigan Ave - New window blinds for Mich Ave Warehouse Leader Office - Keith Littler 313-858-0250	MICSC	FO_DWEST
12353922		7/21/2025	ground water intrusion on inground hoist pit in bay 3 at Michigan Ave Garage loc	MICSC	FO_DWEST
12437381		9/4/2025	Michigan Ave Garage wash bay overhead door cable broken. Door is closed but has trailer stuck inside	MICSC	FO_DWEST
12488825	Y	9/29/2025	Michigan Ave Installation of a 6-50R 240 volt 50amp receptacle in bay 6 Michigan ave garage. John Ki	MICSC	FO_DWEST
12489927		9/30/2025	Michigan Ave - Air water separator leaking shop air, causing air compressor to cycle often. This is	MICSC	FO_DWEST
12500270		10/6/2025	Michigan Ave Garage - During a Safety Walk down, a question asked about yellow tape/paint indicator	MICSC	FO_DWEST
12532145	Y	10/21/2025	SR #12353922 (ground water intrusion on inground hoist pit in bay 3 at Michigan Ave Garage loc) the	MICSC	FO_DWEST
12577033	Y	11/14/2025	Michigan Ave - To replace light bulbs in the warehouse that are out causing a safety hazard. - Micha	MICSC	FO_DWEST
12595062	Y	12/1/2025	Michigan Ave please update lights in Michigan Ave garage very hard to see under work areas. please u	MICSC	FO_DWEST
12595082	Y	12/1/2025	Michigan Ave - Heat not working in the Men's bathroom in the Garage space. there was a space heated	MICSC	FO_DWEST
U-21973 AGDG-4.161 Michigan Ave Service Requests					

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.161d

Respondent: A. E. Jackson

Page: 1 of 1

Question: Refer to pages 67-69 of Ms. Jackson's direct testimony on the Michigan Ave. Service Center Renovation project. Please:

d. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Answer: The Michigan Ave Service Center Renovation project is currently in the planning and scoping phase. Engineering Design is the next phase and is expected to be completed by the end of 2026. The Company will request contractor bid pricing in the 1st quarter of 2027. The project is planned to be completed by the end of September 2027.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-4.161e
Respondent: A. E. Jackson
Page: 1 of 2

Question: Refer to pages 67-69 of Ms. Jackson's direct testimony on the Michigan Ave. Service Center Renovation project. Please:

e. Provide the cost/benefit analysis with the net present value calculations in Excel showing the project is economically justified.

Answer: The Company did not complete a cost/benefit analysis for the Michigan Ave service center renovation project.

The Company evaluates facility renovation projects utilizing Vanderweil Facility Advisors (VFA) software and utilizes the Facilities Condition Index (FCI). FCI is a key benchmarking metric used in facility management to measure the physical condition of a building or portfolio by comparing the total cost of existing deficiencies (deferred capital) to the building's current replacement value (CRV). It is calculated as

$$\frac{\text{Total Cost of Deficiencies}}{\text{Current Replacement Value}} \times 100$$

Total Cost of Deficiencies Current Replacement Value×100, providing a percentage that helps prioritize maintenance, capital renewal, and repair funding.

FCI Score Ranges and Meaning:

- **0–5% (Excellent):** New or well-maintained building, little to no maintenance needed.
- **5–10% (Good):** Normal wear and tear, requires routine maintenance.
- **10–30% (Fair):** Significant repairs needed; aging components are showing wear.
- **30–100% (Critical):** Major renovations required; the cost of repairs is high relative to the value of the asset.

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-4.161e

Respondent: A. E. Jackson

Page: 2 of 2

Key Aspects of the FCI:

- **Purpose:** It acts as an "investment compass" to guide financial decisions, allowing owners to compare the condition of different buildings within a portfolio.
- **Data Source:** FCI is derived from Facility Condition Assessments (FCAs), which evaluate structural, mechanical, and electrical systems.
- **Calculation Components:** It uses the *Current Replacement Value* (CRV), which is the cost to build a brand-new, similar facility today, not the historical cost.
- **Industry Standard:** Originally published by NACUBO in 1991, it is now widely used for schools, government buildings, and commercial real estate to manage building lifecycles.

The Michigan Avenue Service centers has an FCI score of 65%, which is at the high end of the Critical Range of our cost-benefit analysis to replace verse repair, and is one of the worst facilities within the Company's facility portfolio.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.59d
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to pages 54 and 55 of Mr. Huffman's direct testimony on the HPP strategic IT project and Self-Service Service Portal. Please:

d. Provide the number of customers that have requested this access or what other information the Company has gathered that shows most HPP customers want access to this information through the website and would use this capability routinely.

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto:

DTE Gas conducted a 2022 study focused on HPP program demographics in Western Michigan. This study explored how customers manage their homes and their opinions about repair services. The study found that certain age groups and customer segments recommended modernizing the customer experience, specifically by adding digital interaction options. The conclusion was that these enhancements would attract customers who would not otherwise enroll unless digital options were available. Additionally, industry benchmarking showed that competitors in the heating and cooling sector were already offering digital experiences, further motivating DTE Gas to provide similar capabilities to remain competitive and attract new customers.

The decision to implement the HPP Self Service is based upon the results of the 2022 customer study and observed trends in digital engagement in similar programs and industries. The rationale is that digital self-service options increase convenience and satisfaction, which in turn increases the likelihood that customers will enroll and remain on the program. This digital experience will help support the 224,173 customers and $108.5 million in gross revenue in witness Huffman's testimony, reducing the overall cost of service for all DTE Gas customers.

Attachment: None

Co-Respondent(s): Legal

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.59f
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to pages 54 and 55 of Mr. Huffman's direct testimony on the HPP strategic IT project and Self-Service Service Portal. Please:

f. Confirm that the Company provides a copy of the contract when customers sign up for HPP service and are given a copy of the service order and invoice for their record when services are provided to the customer. If not confirming, explain why this information is not provided to the customer in hard copy.

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto:

The Company provides a set of terms and conditions for coverage when the customer enrolls in the Home Protection Plus program along with a welcome letter that identifies the plan selection, appliances eligible for repair service and the location of the property in which they have enrolled for the service plan. The Company does not provide invoices for HPP visits because the program operates as a subscription service. Repairs completed under the plan are included as part of the customer's existing coverage, and no additional charges are assessed at the time of service; therefore, an invoice is not generated.

Attachment: None

Co-Respondent(s): Legal

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.60a
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to lines 15-19 on page 56 of Mr. Huffman's direct testimony on the HPP strategic IT project and Self-Service Service Portal. Please:

a. Explain how giving customers access to a portal grows the number of customers participating in the HPP.

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto:

Please refer to the information provided in response to BMK-6.9c.

Attachment: None

MPSC Case No: U-21973
Requester: Staff
Question No.: BMK-6.9c
Respondent: J. L. Huffman
Page: 1 of 1

Question: The following questions pertain to audit response BMK-4.7:
c. how is the availability of the HPP Self-Service Portal anticipated to grow and retain customers?

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto:

The HPP Self-Service Portal is a strategic digital initiative designed to modernize and enhance the customer experience for Home Protection Plus (HPP) program participants. Its availability is anticipated to both grow and retain customers through several key mechanisms. By offering a self-service portal, DTE Gas is positioned to attract new customers who might not otherwise enroll, expanding the program's reach beyond traditional channels. The portal allows customers to enroll, review their plans, track completed repairs, and manage service requests online—functions previously only available via call center agents. This digital access provides quicker, more transparent service, and more visibility about enrollment times, plan confirmation, and service scheduling. The HPP Self-Service Portal ensures DTE Gas remains competitive and responsive to evolving customer needs, helping to attract and retain customers who might otherwise choose alternative providers. By retaining and growing the customer base, the portal helps sustain program revenues, which offset overall rates for all DTE Gas customers.

Attachment: None

Co-Respondent(s): Legal

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.60b
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to lines 15-19 on page 56 of Mr. Huffman's direct testimony on the HPP strategic IT project and Self-Service Service Portal. Please:

b. Provide a copy of the cost/benefit analysis in Excel with formulas intact and all assumptions clearly explained showing that this project is economically beneficial and the present value of the incremental revenues will exceed the incremental costs of the project.

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto:

An Excel document of this type does not exist. The Company's position is that the overall margin contribution generated by the HPP Program supports the business decision to invest in strategic initiatives that enhance and sustain the program.

As outlined in Witness Huffman's testimony, the HPP Program produces revenues that exceed the full cost of operating it. These net revenues benefit all customers - including those not enrolled in HPP - by flowing into the rate setting process and helping to offset future revenue requirements. As a result, all DTE Gas customers experience lower overall rates.

Attachment: None

Co-Respondent(s): Legal

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

DTE Gas Response to DR AGDG-2.61c

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.61c
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to page 57 of Mr. Huffman's direct testimony on the HPP Product Enhancements IT project. Please:

c. Explain what existing plan offerings the Company wants to modify.

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto.

DTE Gas is implementing updates to its portfolio of customer plans to ensure they are properly aligned with the regions in which they are intended to be offered.

As part of this effort, certain system adjustments were required so that plan availability accurately reflects our intended service areas.

In addition, we are enhancing the flexibility of some plans to allow customers greater ability to tailor their selections.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.61d
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to page 57 of Mr. Huffman's direct testimony on the HPP Product Enhancements IT project. Please:

d. Explain why with the current system the Company cannot modify existing plan offerings, update prices, and offer the plan to customers in regions where the HPP has not been previously offered.

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto:

This project is not implementation of a new system. This project is implementing changes within the current Customer and Relationship Billing System. Activities such as adding a new ZIP code are not self-service and must be done by information technology specialists. All changes to the program require specific information technology coding knowledge, even changes to prices.

Attachment: None

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

DTE Gas Response to DR AGDG-2.61e

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.61e
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to page 57 of Mr. Huffman's direct testimony on the HPP Product Enhancements IT project. Please:

e. What process changes does the Company want to make that cannot be done with the current system and require a new or upgraded system? What will these new processes accomplish?

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto:

The process changes that the Company is making are related to where data is stored within the current system and how we use that data to manage the customer while they are enrolled in HPP. Process changes are for our program management staff to view enrollment time period against costs incurred to serve particular plans and determine if changes are required to the plan to better service the customer or manage the program.

Attachment: None

DTE Gas Response to DR AGDG-2.61f

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.61f
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to page 57 of Mr. Huffman's direct testimony on the HPP Product Enhancements IT project. Please:

f. Regarding the tools and information identified on lines 17-22, does the current system provide or not provide the customer service agents with access to this information? If not, what information is lacking and how critical is that information in answering customer calls for service?

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto:

The information referenced in page 57 of Witness Huffman's testimony does provide agents with the information contained within the new tool. However, the information is held within multiple screens where agents are required to navigate in order to see the information and communicate with the customer. The tool implemented allows for the information to be consolidated into one screen enabling the customer to have a holistic view of the customers enrollment and service history so that they avoid misinformation while they are navigating from screen to screen within the current system.

Attachment: None

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

DTE Gas Response to DR AGDG-2.62a

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.62a
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to page 58 of Mr. Huffman's direct testimony on the HPP Product Enhancements project and customer benefits. Please:

a. Explain how the enhancements will increase HPP revenue, how much and when.

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto:

The enhancements referenced are operational in nature and are intended to improve the overall customer experience and administrative accuracy of the HPP offerings, to sustain but not necessarily to increase revenue. Please refer to Witness Uzenski's Schedule A.13, C3, line 11.

Attachment: None

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

DTE Gas Response to DR AGDG-2.62b

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.62b
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to page 58 of Mr. Huffman's direct testimony on the HPP Product Enhancements project and customer benefits. Please:

b. Provide a copy of the cost/benefit analysis in Excel with formulas intact and all assumptions clearly explained showing that this project is economically beneficial and the present value of the incremental revenues will exceed the incremental costs of the project.

Answer: DTE Gas objects to this request for the reason that the requested information is not relevant or proportional to the needs of the case. Specifically, under MCL 460.10ee, HPP operates as an unregulated value-added program. DTE Gas fulfills its statutory obligation by filing an annual report that itemizes cost allocations between the Company and these programs. Without waiving said objection and subject thereto:

An Excel document of this type does not exist. The Company's position is that the overall margin contribution generated by the HPP Program supports the business decision to invest in strategic initiatives that enhance and sustain the program.

As outlined in Witness Huffman's testimony, the HPP Program produces revenues that exceed the full cost of operating it. These net revenues benefit all customers—including those not enrolled in HPP—by flowing into the rate setting process and helping to offset future revenue requirements. As a result, DTE Gas customers experience lower overall rates.

Attachment: None

Co-Respondent(s): Legal

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

DTE Gas Response to DR AGDG-6.261a

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.261a
Respondent: A. Bolda
Page: 1 of 1

Question: Refer to pages 30-31 of Mr. Bolda's direct testimony on the Gas Utility Network Model. Please:

a. Provide the cost of this project by year from inception to completion split between capital expenditures and O&M expense. If this project is being done in conjunction with a similar project at DTE Electric, provide the same information for total company combined for the two utilities.

Answer: While the ESRI Utility Network (UN) platform is used by both DTE Gas and DTE Electric, the Gas Utility Network Model project has different functionality requirements, scopes, and implementation timelines. As a result, the projects are planned and executed separately, and there is no joint Gas and Electric implementation.

Gas Utility Network Model	Capital	O&M
2023	$431,300	$68,000
2024	$451,000	$4,500
2025	$0	$0
2026	$4,381,000	$435,000
2027	$3,423,000	$463,700
2028	$3,297,800	$465,900
2029	$782,700	$193,600

Attachment: None.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

DTE Gas Response to DR AGDG-6.261b

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.261b
Respondent: A. Bolda
Page: 1 of 1

Question: Refer to pages 30-31 of Mr. Bolda's direct testimony on the Gas Utility Network Model. Please:

b. Identify the phase of project development that the project is currently in, when the detailed system requirements phase will be completed, and the scheduled implementation date.

Answer: The Gas Utility Network Model project initiated a proof-of-concept (POC) in 2023. In 2024, as reflected in my direct testimony on pages ALB – 30,31, the Company established the development and QA environment in preparation for the full Utility Network (UN) implementation. Subsequent project execution was paused and deferred due to higher-priority IFS Mobile Work Management (MWM) implementation investments required for business continuity in 2025. The project is currently in the planning phase, with the full product implementation is targeted for March 2029.

Attachment: None.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

DTE Gas Response to DR AGDG-6.267b

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.267b
Respondent: A. Bolda
Page: 1 of 1

Question: Refer to pages 39-41 of Mr. Bolda's direct testimony on the ClickSoft and MWM Enhancements project. Please:

b. Explain whether the IFS MWM Enhancement project is the same project as the MWM project described beginning on page 35, or if it is an additional project. If it is an additional project, explain why it is not integrated as part of the larger project and provide the additional cost by year from inception to completion.

Answer: The IFS MWM Enhancement project is a separate project from the non-discretionary Field Service Edge (FSE) Replacement implmentation described beginning on page ALB-35 of my direct testimony. The FSE Replacement project is focused on delivering a like-for-like replacement of the ClickSoft Field Service Edge system within the required implementation timeframe.

The IFS MWM Enhancement project that addresses additional functionality that could not be delivered within the schedule and scope of the initial MWM implementation. Accordingly, these enhancements were intentionally scoped and managed as a separate project rather than integrated into the core FSE Replacement effort.

Attachment: None.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

DTE Gas Response to DR AGDG-6.267c

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.267c
Respondent: A. Bolda
Page: 1 of 1

Question: Refer to pages 39-41 of Mr. Bolda's direct testimony on the ClickSoft and MWM Enhancements project. Please:

c. Provide the phase of development that the MWM Enhancement system is currently in, when the detailed requirements phase will be completed, and the scheduled implementation date.

Answer: As reflected in U-21973, Exhibit A-12, Schedule B5.4.1, line 17, the IFS MWM Enhancement project is scheduled to begin in 2027.

Attachment: None.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

Exhibit: AG-18
Case No: U-21973
March 13, 2026

Adjustments to Capital Expenditures, Rate Base and Depreciation Expense

($000)

Line	Description	Capital Expenditure Reductions [1] 2024	2025	9 M/E Sep 2026	12 M/E Sep 2027	Total	Rate Base Reduction	Depreciation Rate [2]	Reduction in Depreciation Expense	Property taxes [3] Rate	Property taxes [3] Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)				
1	**Distribution Plant:**										
2	Main Renewals		$ 7,604	$ 141	$ 1,795	$ 9,540	$ 8,643	2.60%	$ 225	$ 0.059500	$ 126
3	Public Improvements		2,898	1,275	2,203	6,376	5,275	2.60%	137	$ 0.059500	61
4	Service Alterations		4,629	661	4,355	9,645	7,468	2.60%	194	$ 0.059500	83
5	Communications & Controls - Meters			2,396	7,507	9,903	6,150	2.60%	160	$ 0.059500	25
6	Customer-Market Attachments			19,406	13,870	33,276	26,341	2.60%	685	$ 0.059500	203
7	System Reliability Projects			89	3,721	3,810	1,950	2.60%	51	$ 0.059500	1
8	IRM 2025 Overspent Amount Disallowed		18,400			18,400	18,400	2.60%	478	$ 0.059500	301
9	**Transmission Plant:**										-
10	South Grand Rapids Pipeline Replacement		1,333	12,755	13,679	27,767	20,928	1.77%	370	$ 0.059500	155
11	East Petosky Pipeline Reinforcement		406	3,266	32,168	35,840	19,756	1.77%	350	$ 0.059500	41
12	**Gas Storage and Compression**										-
13	Columbus 23 Upgrade				2,300	2,300	1,150	2.30%	26	$ 0.059500	-
14	Belle River Mills Z5 Engine and Compressor				6,100	6,100	3,050	2.30%	70	$ 0.059500	-
15	Belle River Mills Unit 8 Turbine Engine				6,000	6,000	3,000	2.30%	69	$ 0.059500	-
16	**General Facilities and Structures**										-
17	Northern Operations Resource Center			1,125	3,750	4,875	3,000	2.74%	82	$ 0.059500	12
18	Michigan Ave. Service Center			200	4,800	5,000	2,600	2.74%	71	$ 0.059500	2
19	**Gas IT Projects**										
20	HPP Self-Service Portal & Enhancements	2,010	1,862	1,313	963	6,148	5,667	20.00%	1,133		
21	Premature IT Projects	451	-	3,286	4,786	8,523	6,130	20.00%	1,226		
22	Total	$ 2,461	$ 37,132	$ 45,913	$ 107,997	$ 193,503	$ 139,505		$ 5,328		$ 1,007
23											
24	**Working Capital** (Exhibit AG-19						18,000				
25											
26	**Total Rate Base Deduction**						$ 157,505				

Source: (1) See AG witness Coppola Direct Testimony.
(2) Depreciation rates from Exhibit A-13, Schedule C6, page 2.
(3) Milleage rate from WP SLW-1 applied to 50% of capital expenditures.

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21973**
DTE Gas Company - Gas Rate Case | **Exhibit AG-19**
March 13, 2026
Working Capital - Summary | **Page 1 of 1**

Line	Description		Millions Of Dollars	Note or Ref.
	(a)		(b)	(c)
1	Test Year Working Capital Per Company		$ 837.2	a
	Attorney General Changes			
2	Income Taxes Payable - set amount equal to historic test year		(12.2)	b
3	Reduce Prepayments - see calculations below		(5.8)	c
4	**Total Changes**	(Sum of L2 to L3)	**$ (18.0)**	
5	**AG Revised Working Capital Level**	(L1 + L4)	**$ 819.2**	
6	**Change in Working Capital**	**(L5 less L1)**	**$ (18.0)**	

a Per Company Exhibit A-12, Schedule B4
b Reflects elimination of Company change between historic and projected test years

c Premapments per AGDG 5.214 (c)

	$ Thous.	Percentage Increase 1 Yr.	Historic TY to Projected TY Equals 2.75 Yrs.
2024	$ 32,803		
2020	23,791		
Four Yr. Change	$ 9,012	8.4%	25.0%
AG Projection of Prepayments Increase ($32.8M Historic level x 25%)			$ 8.2
Less DTE Gas Change in Prepayments ($46.8 M vs. $32.8 M)			14.0
Reduction in Prepayments			**$ (5.8)**

To Line 3 Above

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-1.14
Respondent: T. M. Uzenski
Page: 1 of 1

Question: Refer to line 16 of Exhibit A-12, Schedule B4, for Prepayments in the calculation of forecasted working capital. Please provide a schedule in Excel showing how the increase from $32.8 million to $46.7 million (a 42% increase) was determined.

Answer: See attachment.

Attachment: U-21973 – AGDG 1.14 – Prepayments

U-21973																								
AGDG-1.14																								
Projected Working Capital		13-Month Average																						
Exhibit A-12, Schedule B4		**Historical Test Year Ending 12/31/24**	**Projected Test Year Ending 9/30/27**	**Change**																				
Prepayments		$ 32,803	$ 46,722	$ 13,919																				
		Adjusted Historical																						
Balance Sheet		12/31/2024	1/31/2025	2/28/2025	3/31/2025	4/30/2025	5/31/2025	6/30/2025	7/31/2025	8/31/2025	9/30/2025	10/31/2025	11/30/2025	12/31/2025	1/31/2026	2/28/2026	3/31/2026	4/30/2026	5/31/2026	6/30/2026	7/31/2026	8/31/2026	9/30/2026	
Prepayments	Beginning Balance		$ 27,750	$ 60,562	$ 51,313	$ 42,064	$ 32,814	$ 23,565	$ 14,316	$ 5,067	$ 66,517	$ 57,268	$ 48,019	$ 38,770	$ 29,521	$ 64,612	$ 54,502	$ 44,392	$ 34,282	$ 24,173	$ 14,063	$ 3,953	$ 73,016	
	Prepaid Property Taxes		$ 42,061	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,699	$ -	$ -	$ -	$ -	$ 45,201	$ -	$ -	$ -	$ -	$ -	$ -	$ 79,173	$ -	
	Property Tax Accruals		$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	
	Ending Balance	$ 27,750	$ 60,562	$ 51,313	$ 42,064	$ 32,814	$ 23,565	$ 14,316	$ 5,067	$ 66,517	$ 57,268	$ 48,019	$ 38,770	$ 29,521	$ 64,612	$ 54,502	$ 44,392	$ 34,282	$ 24,173	$ 14,063	$ 3,953	$ 73,016	$ 62,907	
	13-Month Average	$ 32,803												$ 38,273										

U-21973													
AGDG-1.14													
Projected Working Capital													
Exhibit A-12, Schedule B4													
Prepayments													
Balance Sheet		10/31/2026	11/30/2026	12/31/2026	1/31/2027	2/28/2027	3/31/2027	4/30/2027	5/31/2027	6/30/2027	7/31/2027	8/31/2027	9/30/2027
Prepayments	Beginning Balance	$ 62,907	$ 52,797	$ 42,687	$ 32,577	$ 71,848	$ 60,499	$ 49,151	$ 37,802	$ 26,454	$ 15,105	$ 3,757	$ 81,575
	Prepaid Property Taxes	$ -	$ -	$ -	$ 50,619	$ -	$ -	$ -	$ -	$ -	$ -	$ 89,167	$ -
	Property Tax Accruals	$ (10,110)	$ (10,110)	$ (10,110)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)
	Ending Balance	$ 52,797	$ 42,687	$ 32,577	$ 71,848	$ 60,499	$ 49,151	$ 37,802	$ 26,454	$ 15,105	$ 3,757	$ 81,575	$ 70,227
	13-Month Average			$ 41,037									$ 46,722

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-5.214a
Respondent: S. L. Wisniewski
Page: 1 of 1

Question: Refer to the response to AGDG-1.14 and related attachment pertaining to the calculation of Prepayments for working capital. Please:

a. Explain and show in Excel the calculation how the Company determined the Prepaid Property Tax amounts.

Answer: The Prepaid Property Tax balance increases when Property Tax payments are made in January and August and decreases when Property tax expense is accrued monthly.

Refer to Prepaid Property Tax Activity tab in the attachment for the calculation of the Prepaid Property Taxes and Property Tax Accruals amounts reflected in AGDG-1.14.

Attachment: U-21973 AGDG-5.214a Prepaid Property Tax

U-21973																							
AGDG-1.14																							
Projected Working Capital		13-Month Average																					
Exhibit A-12, Schedule B4		Historical Test Year Ending 12/31/24	Projected Test Year Ending 9/30/27	Change																			
Prepayments		$ 32,803	$ 46,722	$ 13,919																			
		Adjusted Historical																					
Balance Sheet		12/31/2024	1/31/2025	2/28/2025	3/31/2025	4/30/2025	5/31/2025	6/30/2025	7/31/2025	8/31/2025	9/30/2025	10/31/2025	11/30/2025	12/31/2025	1/31/2026	2/28/2026	3/31/2026	4/30/2026	5/31/2026	6/30/2026	7/31/2026	8/31/2026	
Prepayments	Beginning Balance		$ 27,750	$ 60,562	$ 51,313	$ 42,064	$ 32,814	$ 23,565	$ 14,316	$ 5,067	$ 66,517	$ 57,268	$ 48,019	$ 38,770	$ 29,521	$ 64,612	$ 54,502	$ 44,392	$ 34,282	$ 24,173	$ 14,063	$ 3,953	
	Prepaid Property Taxes		$ 42,061	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,699	$ -	$ -	$ -	$ -	$ 45,201	$ -	$ -	$ -	$ -	$ -	$ -	$ 79,173	
	Property Tax Accruals		$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (9,249)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	
	Ending Balance	$ 27,750	$ 60,562	$ 51,313	$ 42,064	$ 32,814	$ 23,565	$ 14,316	$ 5,067	$ 66,517	$ 57,268	$ 48,019	$ 38,770	$ 29,521	$ 64,612	$ 54,502	$ 44,392	$ 34,282	$ 24,173	$ 14,063	$ 3,953	$ 73,016	
	13-Month Average	$ 32,803												$ 38,273									

U-21973														
AGDG-1.14														
Projected Working Capital														
Exhibit A-12, Schedule B4														
Prepayments														
Balance Sheet		9/30/2026	10/31/2026	11/30/2026	12/31/2026	1/31/2027	2/28/2027	3/31/2027	4/30/2027	5/31/2027	6/30/2027	7/31/2027	8/31/2027	9/30/2027
Prepayments	Beginning Balance	$ 73,016	$ 62,907	$ 52,797	$ 42,687	$ 32,577	$ 71,848	$ 60,499	$ 49,151	$ 37,802	$ 26,454	$ 15,105	$ 3,757	$ 81,575
	Prepaid Property Taxes	$ -	$ -	$ -	$ -	$ 50,619	$ -	$ -	$ -	$ -	$ -	$ -	$ 89,167	$ -
	Property Tax Accruals	$ (10,110)	$ (10,110)	$ (10,110)	$ (10,110)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)	$ (11,348)
	Ending Balance	$ 62,907	$ 52,797	$ 42,687	$ 32,577	$ 71,848	$ 60,499	$ 49,151	$ 37,802	$ 26,454	$ 15,105	$ 3,757	$ 81,575	$ 70,227
	13-Month Average				$ 41,037									$ 46,722

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21973**
DTE Gas Company - Gas Rate Case | **Exhibit AG-21**
Date: March 13, 2026
Recommended Capital Structure & Cost Rates for |
Projected Year Ending September 2027 (Thousands of Dollars)

Line	Description	Note	DTE Gas - Capital Structure Capital Balances	% Permenant Capital	% Total Capital	Cost Rate*	Total Cost (d) x (e)	Conversion Factors**	Pre-Tax Wtd. Cost (f) x (g)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Long Term Debt	(A)	$3,279,308	50.00%	40.82%	4.59%	1.87%	1.0000	1.87%
2	Preferred Stock		-	0.00%	0.00%		0.00%		0.00%
3	Common Equity	(A)	3,279,345	50.00%	40.82%	9.80%	4.00%	1.3547	5.42%
4	Total Permanent Capital	(B)	6,558,653	100.00%	81.64%		5.87%		7.29%
5	Short Term Debt	(B)	91,581		1.14%	5.06%	0.06%	1.0000	0.06%
6	Deferred Income Taxes	(B)	1,383,391		17.22%	0.00%	0.00%	1.0000	0.00%
7	JDITC								
8	Long Term Debt		-		0.00%	4.59%	0.00%	1.0000	0.00%
9	Preferred Stock		-		0.00%	0.00%	0.00%	-	0.00%
10	Common Equity		-		0.00%	9.80%	0.00%	1.3547	0.00%
11	Total JDITC		-						
12	**Total Capitalization & Cost Rates**		$8,033,625		100.00%		**5.93%**		**7.35%**

Notes

* The Cost of Long Term Debt is from page 2 of this exhibit and the Cost of Common Equity is set forth on Exhibit AG-22. Costs on lines 5 and 6 are from Exhibit A-14, Sched. D1.

** See Company Exhibit A-13, Schedule C2.

(A) Reflects the permanent capital of DTE Gas. per Exhibit A-14, Sched. D1, with equal amounts of equity and long-term debt.

(B) Capital balances per Company Exhibit A-14, Schedule D1.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Cost of Long-Term Debt

Case No. U-21973
Exhibit AG-21
Date: March 13, 2026

($000)

Line	Description or Caption	Projected Test Year Ending September 2027 Long-Term Debt Outstanding	Interest Expense	Cost Rate Col. (c) / (b)
	(a)	(b)	(c)	(d)
1	Exhibit A-14, Schedule D2 (line 30) Long-Term Debt Cost Developed	$ 3,356,000	$ 156,180	4.65%
2	Less: 100% of New Debt Issue - Line 28 of Exhibit A-14, Schedule D2 Debt and Cost*	(150,000)	(9,046)	
3	Add: 8.33% of New Debt Issue from line 2 above*	12,500	754	
4	AG's Revised Cost of Long-Term Debt	**$ 3,218,500**	**$ 147,888**	**4.59%**

* The 8,33% factor reflects one-twelfth of the annual amount.
On Exhibit A-14, Schedule D2, the Company claims that it will issue new long-term debt in 2027 on September 1, 2027 or one month before the end of the projected test year. The adjustments on lines 2 and 3 above reflect inclusion of the new debt for one month (vs. 12 months).

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Case No. U-21973
Exhibit AG-22
Date: March 13, 2026
Page 1 of 1

Summary of Cost of Common Equity Analysis

Line	Description	Relative Weighting	DTE Gas Company Proxy Rates	Note
	(a)	(b)	(c)	(d)
1	Discounted Cash Flow Approach (DCF)	50.00%	9.96%	1
2	Capital Asset Pricing Model Approach (CAPM)	25.00%	9.88%	2
3	Utility Equity Risk Premium Approach	25.00%	9.40%	3
4	**Calc. Cost of Common Equity (Sum of Col. (b) x (c) for Lines 1, 2 and 3)**		**9.80%**	

Note 1 See Exhibit AG-23
Note 2 See Exhibit AG-24
Note 3 See Exhibit AG-25

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21973**
DTE Gas Company - Gas Rate Case | **Exhibit AG-23**
Date: March 13, 2026
Page 1 of 1

Discounted Cash Flow (DCF) Application
(See Equation Below)

Line	Company	Ticker	Average 30 Day High Low Price*	Projected 2026 Ann. Dividend**	Dividend Yield	EPS Growth Rate***			DCF ROE for Each Co.
						Value Line	S&P Capital IQ	Average of	
	(a)	(b)	(c)	(d)	Col. (d)/(c) (e)	(f)	(g)	Col. (f) & (g) (h)	Col. (e) + (h) (i)
	Proxy Group								
1	Atmos Energy	ATO	$ 170.70	4.00	2.34%	7.00%	7.22%	7.11%	9.45%
2	Chesapeake Utilities	CPN	130.45	2.82	2.16%	N/M	N/A	N/M	N/A
3	NiSource	NI	42.18	1.20	2.84%	N/M	7.70%	7.70%	10.54%
4	New Jersey Resources	NJR	46.57	1.90	4.08%	6.50%	7.90%	7.20%	11.28%
5	Northwest Natural Holdings	NWN	47.37	1.97	4.16%	6.50%	5.75%	6.13%	10.28%
6	One Gas	OGS	79.56	2.72	3.42%	4.50%	5.94%	5.22%	8.64%
7	WEC Energy Group	WEC	107.17	3.81	3.56%	6.00%	N/A	6.00%	9.56%
8	Average				***3.22%***	***6.10%***	***6.90%***	***6.56%***	***9.96%***
9	High								10.54%
10	Low								8.64%

* Average of High and Low prices per Yahoo from November 18, 2025 to December 31, 2025

** Value Line Projected Dividends for 2026 published November 21, 2025 and for WEC Energy on December 5, 2025

*** Value Line Growth data as of November 21 and December 5, 2025. S&P Capital IQ data per Company Exhibit A-14, Schedule D5.2, page 1 of 3, column 6

N/A Data not available

N/M Forecasted EPS growth rates of 8% or higher are unrealistic for gas distribution companies that has customer growth of less than 3%.

Equation **R = D/P + g** *Where* **R** = the required return on the equity security; **D** = the next dividend on the security; **P** = the current price of the equity security; **g** = the expected growth rate of earnings

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company. - Gas Rate Case

Case No. U-21973
Exhibit AG-24
Date: March 13, 2026

Capital Asset Pricing Model Application
(See Equation Below)

Line	Company & Ticker		% Common Equity	Current Beta (B)	Risk Premium (R_p)	Beta x Risk Premium Col. (c) x (d)	Risk Free Rate (R_f)	K_e or CAPM ROE for Each Co. Cols. (e) + (f)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)
	Proxy Group							
1	Atmos Energy	ATO	60.2%	0.75	7.45%	5.59%	4.35%	9.94%
2	Chesapeake Utilities	CPK	52.4%	0.70	7.45%	5.22%	4.35%	9.57%
3	NiSource	NI	35.0%	0.85	7.45%	6.33%	4.35%	10.68%
4	New Jersey Resources	NJR	43.2%	0.75	7.45%	5.59%	4.35%	9.94%
5	Northwest Natural Holdings	NWN	40.5%	0.75	7.45%	5.59%	4.35%	9.94%
6	One Gas	OGS	56.3%	0.75	7.45%	5.59%	4.35%	9.94%
7	WEC Energy Group	WEC	39.9%	0.65	7.45%	4.84%	4.35%	9.19%
8	**Average**		**46.8%**	**0.74**	**7.45%**	**5.53%**	**4.35%**	***9.88%***
9	High							10.68%
10	Low							9.19%

Sources

Column (b) Per SEC Filings: Average for the four quarters ended September 2025

Column (c) From the Value Line Investment Survey published November 21 and December 5, 2025.

Column (d) Reflects the average returns of Large Stocks (12.29%) vs Long Term Gov't Bond Income Returns (4.84%) for the period 1926 to 2024 per the Ibbotson Clasic Year Book (through 2022) and "slick charts" for 2023 and 2024

Column (f) Page 14 of the Blue Chip Financial Forecast of June 2, 2025 shows the 30 year U.S Treasury bond at 4.4% and 4.3% for 2027 and beyond (a 4.35% avg.). (Workpaper JEN 24)

Equation for CAPM $K_e = R_f + (B \times R_p)$

Where K_e = the Cost of Common Equity; R_f = the Risk Free Rate of Return;
B = the Beta or covariance of the stocks price to overall market ; and
R_p = the Expected Risk Premium of the overall market

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Utility Equity Risk Premium Approach

Case No. U-21973
Exhibit AG-25
Date: March 13, 2026

Line	Description	Rate Developed	Note
	(a)	(b)	(c)
1	Number of Companies in proxy group	7	
2	Average Rating	A/BBB	1
3	Projected "A" rated Bonds New Issue Rate	5.54%	2
4	Historical Spread - Gas Util. Common Stocks vs. "A" Rated Utility Bonds	3.86%	3
5	Sub Total - Rate for "A" rated companies (lines 3 + 4)	**9.40%**	

Note:

1 Atmos, OneGas, New Jersey Natural Gas and Chesapeake Utilities are "A" rated. All other peer companies are "BBB" rated

2 Based on analysis of new 30 Year issues for 2024 (see workpapers)

"A" Rated Spread to 30 Yr. Treasuries	1.19%	
Assumed 30 Year US Treasury Bond Rate (from CAPM Analysis)	4.35%	
Projected "A" rated 30 Year bonds	**5.54%**	***To Line 3 above***

3 Per AG Workpaper AG25A.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Case No. U-21973
Exhibit AG-26
Date: March 13, 2026

Peer Group Non-Utility or Non Regulated Operations

Line	Company & Ticker		Percent Common Equity*	Current Beta (*B*)	Utility Business	Non Utility & Non Reg. Business		Measure-ment Criteria	SEC Filing Information SEC Form	Period Ending	Page
	(a)		(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)
	Proxy Group										
1	Atmos Energy	ATO	60.2%	0.75	***64.4%***	***35.6%***	A	Net Income	10-K	Sep. 24	27
2	Chesapeake Utilities	CPK	52.4%	0.70	***86.0%***	***14.0%***	B	Op. Income	10-K	Dec. 24	33
3	NiSource	NI	35.0%	0.85	***100.0%***	***0.0%***		Net Income	10-K	Dec. 24	7
4	New Jersey Resources	NJR	43.2%	0.75	***46.0%***	***54.0%***	C	Net Income	10-K	Dec. 24	35
5	Northwest Natural Hldgs.	NWN	40.5%	0.75	***90.6%***	***9.4%***	D	Op. Income	10-K	Dec. 24	98
6	One Gas	OGS	56.3%	0.75	***100.0%***	***0.0%***		Revenues	10-K	Dec. 24	7
7	WEC Energy Group	WEC	39.9%	0.65	***76.0%***	***24.0%***	E	Net Income	10-K	Dec. 24	157
8	**Average**		46.8%	0.74	***80.4%***	***19.6%***					

* Reflects Average Capitalization for the four quarters ended June 2025

A Pipeline and Storage

B Non Utility is primarily Propane Distribution

C Primarily Clean Energy Ventures and Energy Services

D Renewable Energy, Storage and Pipelines

E Non-Utility Energy Infrastructure

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Case No. U-21973
Exhibit AG-27
Date: March 13, 2026

Market to Book Equity Ratios

Line	Company & Ticker		Sep. 30, 2025 Mkt. Price p/ Sh.	September 30, 2025 Book Value of Common Equity ($Mil.)	Shares Outstanding (Millions)	Book Value Per Sh.	Market to Book Ratio
	(a)		(b)	(c)	(d)	(e)	(f)
	Proxy Group						
1	Atmos Energy	ATO	170.75	14,283.0	161.6	88.38	1.9
2	Chesapeake Utilities	CPK	134.69	1,519.0	22.8	66.62	2.0
3	NiSource	NI	43.30	8,883.0	470.8	18.87	2.3
4	New Jersey Resources	NJR	48.15	2,392.0	100.5	23.80	2.0
5	Northwest Natural Hldgs.	NWN	44.93	1,434.0	41.5	34.55	1.3
6	One Gas	OGS	80.94	3,182.0	60.0	53.03	1.5
7	WEC Energy Group	WEC	114.59	13,568.0	325.3	41.71	2.7
8	**Average**						**2.0**

Col. (b) Closing Price Per Yahoo
Col. (c) Per SEC Filings
Col. (d) Per SEC Filings
Col. (e) Equals Col. (c) divided by Col. (d)
Col. (f) Equals Col. (b) divided by Col. (e)

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-21973**

DTE Gas Company - Gas Rate Case **Exhibit AG-28**

Date: March 13, 2026

Gas Regulatory Decisions - Authorized ROE's under 9.9% - 12 Mo. Periods Ended September 2024 and 2025

Line	Gas Company*	Order Date & Jurisdiction*			ROE Rate from Order* 2023-24	ROE Rate from Order* 2024-25	Parent Company	Long Term Debt Issued Since Rate Order**			
1	Piedmont Natural Gas	Oct	5	SC	9.30%		Duke Energy	$150M	4.85%	3/5 Yr	(Nov 2023)
2	Chattanooga Gas	Oct	6	TN	9.80%		Southern Co.	$400M	5.70%	10 Yr	(Feb 2024)
3	New Youk State Elec. & Gas	Oct	12	NY	9.20%		Avangrid	$680M	Var. Rates	Var. Mat.	(Dec 2023)
4	Rochester Gas & Electric	Oct	12	NY	9.20%		Avangrid	$680M	Var. Rates	Var. Mat.	(Dec 2023)
5	Northwestern Energy	Oct	25	MT	9.55%		NorthWestern Energy				
6	Minnesota Energy Rescs	Oct	26	MN	9.65%		WEC Energy				
7	Avista	Oct	26	OR	9.50%		Avista				
8	Duke Energy Onio	Nov	1	OH	9.60%		Duke Energy	$150M	4.85%	3/5 Yr	(Nov 2023)
9	Madison Gas & Electric	Nov	3	WI	9.70%		MGE Corp				
10	Questar Gas	Nov	7	WY	9.65%		Dominion Energy	$1.0 Bil	5/5.35%	10/30 Yr.	(Feb 2024)
11	Northern States Power	Nov	9	FL	9.80%		Xcel Energy				
12	Wisconsin Power & Light	Nov	9	WI	9.80%		Alliant Energy				
13	Ameren Illinois	Nov	16	IL	9.44%		Ameren	$700M	4.38%	5 Yr	(Dec 2023)
14	North Shore Gas	Nov	16	IL	9.38%		WEC Energy	$20M	5.82%	5 Yr	(Dec 2023)
15	Northern Illinois Gas	Nov	16	IL	9.51%		Southern Co.	$400M	5.70%	10 Yr	(Feb 2024)
16	Peoples Gas Light & Coke	Nov	16	IL	9.38%		WEC Energy				
17	Piedmont Natural Gas	Dec	4	TN	9.80%		Duke Energy	$150M	4.85%	3/5 Yr	(Nov 2023)
18	Baltimore Gas & Electric	Dec	14	MD	9.45%		Exelon	$1.7 B	5.2/5.4/5.6%	5/10/20 Yrs	(Feb 2024)
19	Washington Gas Light	Dec	14	MD	9.50%		AltaGas BB Rated	900 M	7.20%	30 Yr.	(Sep 2024)
20	Washington Gas Light	Dec	15	MD	9.65%		AltaGas BB Rated	900 M	7.20%	30 Yr.	(Sep 2024)
21	Mountaineer Gas	Dec	21	WV	9.75%		UGI				
22	Black Hills Wyoming Gas	Jan	17	WY	9.85%		Black Hills	$450 M	6.00%	10 Yr.	(May 2024)
23	Texas Gas Service	Jan	31	TX	9.70%		One Gas	$250 M	5.10%	5 Yr	(Aug 2024)
24	Black Hills Colorado	Mar	24	CO	9.30%		Black Hills	$450 M	6.00%	10 Yr.	(May 2024)
25	Southwest Gas - North	Apr	8	NV	9.50%		Southwest Gas				
26	Southwest Gas - South	Apr	8	NV	9.50%		Southwest Gas				
27	Northeast Ohio Nat. Gas	Apr	17	OH	9.75%		First Energy	$800 M	4.88%	15 Yr.	(Aug 2024)
28	CenterPoint Energy	Jun	26	TX	9.80%		CenterPoint Energy	$800 M	6.90%	31 Yr.	(Aug 2024)
29	Fitchburg Gas & Elec.	Jun	28	MA	9.40%		Unitil				
30	Central Hudson Gas & Elec.	Jul	18	NY	9.50%		Fortis				
31	New Mexico Gas	Jul	25	NM	9.38%		Emera				
32	Northern Indiana Pub. Serv.	Jul	31	IN	9.75%		NiSource	$500 M	6.37%	30 Yr.	(Sep 2024)
33	KeySpan Gas East	Aug	15	NY	9.35%		National Grid P. C.				
34	Brooklyn Union Gas	Aug	15	NY	9.35%		National Grid P. C.				
35	Interstate Power & Light	Sep	17	IA	9.65%		Alliant Energy				
36	Sierra Pacific Power	Sep	18	NV	9.45%		Berkshire Hathaway				
37	Michigan Gas Utilities	Sep	26	MI	8.86%		WEC Energy	$25 M	4.8%/5.2%	5 & 10 Yr.	(Oct 2024)
					9.53%						

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-21973**

DTE Gas Company - Gas Rate Case **Exhibit AG-28**

Date: March 13, 2026

Gas Regulatory Decisions - Authorized ROE's under 9.9% - 12 Mo. Periods Ended September 2024 and 2025

Line	Gas Company*	Order Date & Jurisdiction*			ROE Rate from Order* 2023-24	ROE Rate from Order* 2024-25	Parent Company	Long Term Debt Issued Since Rate Order**			
1	Black Hills Arkansas	Oct	25	AR		9.85%	Black Hills				
2	Public Service Elec. & Gas	Oct	26	NJ		9.60%	Pub. Serv. Enterprises Group	$1.0 B	4.9%/5.5%	5 & 10 Yr.	(Mar 2025)
3	Northwest Natural Gas	Oct	26	OR		9.40%	Northwest Natural Holdings	$325 M	7.00%	30 Yr.	(Mar 2025)
4	Public Service of Colorado	Nov	1	CO		9.35%	Xcel Energy	$1.1 B	4.8%/5.2%	5 & 10 Yr.	(Mar 2025)
5	DTE Gas	Nov	7	MI		9.80%	DTE Energy	$1.1 B	5.20%	5 Yr	(Feb 2025)
6	Connecticut Nat. Gas	Nov	9	CT		9.15%	Avangrid				
7	Sthrn. Connecticut Nat. Gas	Nov	9	CT		9.15%	Avangrid				
8	Texas Gas Service	Nov	16	TX		9.70%	One Gas				
9	Elizabethtown Gas	Nov	16	NJ		9.60%	JP Morgan Infrast via S J Ind.				
10	New Jersey Natural Gas	Nov	16	NJ		9.60%	N J Resources				
11	Summitt Utilities	Nov	16	AR		9.85%	Kinder Morgan Ptns.				
12	National Fuel Gas	Dec	4	NY		9.70%	National Fuel Gas	$1.0 BM6	5.5%/5.9%	5 & 10 Yr.	(Feb 2025)
13	Wisconsin Gas	Dec	14	WI		9.80%	WEC Energy	$300 M	4.55%	5 Yr	(Dec 2024)
14	Wisconsin Public Svc.	Dec	14	WI		9.80%	WEC Energy	$300 M	4.55%	5 Yr	(Dec 2024)
15	Avista Washington	Dec	15	WA		9.80%	Avista				
16	Columbia Gas	Dec	21	KY		9.75%	NiSource	$1.0 B	5.75%	30 Yr	(Nov 2025)
17	Piedmont Natural Gas	Jan	7	NC		9.80%	Duke Energy	$1.0 B	4.95%/5.7%	10 Yr & 30 Y	(Sep 2025)
18	Northern States Por - MN	Feb	13	MN		9.60%	Exel				
19	Cascade Natural Gas	Feb	24	WA		9.50%	MDU Resources				
20	Orange & Rockland	Mar	20	NY		9.75%	Consolidated Edison				
21	Southwest Gas	Mar	27	AZ		9.84%	Sowthwest Gas Holdings				
22	Columbia Gas of MD	Apr	22	MD		9.80%	NiSource	$1.0 B	5.75%	30 Yr	(Nov 2025)
23	Atmos TX	May	13	TX		9.80%	Atmos	$600M	5.45%	30 Yr	(Sep 2025)
24	Columbia Gas VA	May	15	VA		9.75%	NiSource	$1.0 B	5.75%	30 Yr	(Nov 2025)
25	Avista OR	May	23	OR		9.50%	Avista				
26	Corning Natural Gas	Jun	12	NY		9.50%	Argo Infrastructure Ptns				
27	Atmos TX	Jun	17	TX		9.80%	Atmos	$600M	5.45%	30 Yr	(Sep 2025)
28	Chesapeake Util	Jun	18	DE		9.60%	Chesapeake Utilities				
29	East Ohio Gas	Jun	26	OH		9.79%	Enbridge				
30	Delta Natural Gas	July	1	KY		9.75%	Essential Utilities				
31	Atmos - KY	Aug	11	Ky		9.75%	Atmos	$600M	5.45%	30 Yr	(Sep 2025)
32	Central Hudson Gas & Electric	Aug	14	NY		9.50%	Fortis				
33	Niagra Mohawk	Aug	14	NY		9.50%	National Grid				
34	Libefrty Utilities	Aug	26	NH		9.30%	Algonquin				
35	Avista	Aug	29	ID		9.60%	Avista				
36	Consumers Energy	Sep	30	MI		9.80%	CMS Energy				
						9.64%					

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-21973**
DTE Gas Company - Gas Rate Case **Exhibit AG-28**
Date: March 13, 2026
Gas Regulatory Decisions - Summary of All Authorized ROEs **Page 3 of 3**

	State	Company /Description	No. of Companies 12 Mo. Ended Sept. 2024	2025	ROEs Awarded 12 Mo. Ended June of 2024	2025	
1	Average ROEs - Companies Under 9.9%		**37**	**36**	**9.53%**	**9.64%**	
2	California	Southern California Gas	1	1	10.50%	10.08%	Wildfire Risk
3	Florida	Peoples Gas System	1		10.15%		Hurricane Risk
4	Alaska	ENSTAR Natural Gas	1		11.88%		Isolated Utility; 150K customers
5	Virginia	Roanoake Gas Company		1		9.90%	Small Company; 63K Customers
6	Indiana	Ohio Valley Gas		1		10.00%	Small Company; 30K Customers
7	Other Jurisdictions						
8	Illinois	Liberty Utilities		1		9.90%	378K Gas Customers (Ill. & NE US)
9	North Dakota	MDU Resources		1		9.90%	Small Operation
10	North Dakota	NSP Minnesota		1		9.90%	Small Operation***
11	Washington	Pudget Sound Gas		1		9.90%	
12	**Cases at 9.9% + with ROEs Stated**		**3**	**7**	**10.84%**	**9.94%**	
13	**Average of All ROEs Awarded**		**40**	**43**	**9.63%**	**9.69%**	

* All ROE data from Regulatory Research Associates & excludes Limited Issue Rider cases
** Customer size information is from SEC documents and Company web sites
*** NSP Minnesota includes certain minor gas operations located in N. Dakota

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Case No. U-21973
Exhibit AG-29
Date: March 13, 2026

2024 Rating Agency Cash Flow Ratios
(With ROE at 9.80% and a 50% Common Equity Ratio)

		2024 Adjusted Moody's Cash Flow Ratio ($ Millions)			
Line	Caption	Cash From Operations Pre-Wkg. Cap.	Debt	Ratio (b) / (c)	Note
	(a)	(b)	(c)	(d)	
1	**2024 Actual Ratio Results**	$ 538	$ 2,883	**18.7%**	1
2	Reduce Common Equity (to 50% vs 51.2%)	-	70		2
3	Increase ROE by 0.7% (to 9.8% vs 9.1%)	20			3
4	**2024 Pro Forma w/50% Common Equity, 9.8% ROE**	$ 558	$ 2,953	**18.9%**	L 1 + L 2 + L 3
5	**Ratings Downgrade Risk**			***Below 16%***	4

Notes

1 From pages 1 and 7 of Moody's July 17, 2025 report on DTE Gas (see JEU-1.1-02)

2 Exhibit A1, Schedule A2, page 3 shows the Company's capital components (51.2% common equity and 48.8% long-term debt).
Reducing common equity by 1.2% ($5.8 billion x 1.2%) is the calculated $70 million adjustment to Debt noted above.

3 Exhibit A1, Schedule A2, page 3 shows DTE Gas earning a 9.1% ROE in 2024 (0.7% the authorized 9.8% ROE).
Increasing the ROE to 9.8% results in an additional $20 million of net income (Common Equity of $2.9 billion x 0.7%).

4 From page 2 of Moody's July 17, 2025 report on DTE Gas (see JEU-1.1-02)

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Case No. U-21973
Exhibit AG-30
Date: March 13, 2026

Most Recent Ordered ROEs of Peer Group

Line	Company & Ticker		Most Recent Authorized ROE*	State	Date	Relevant Gas Utility Units
	(a)					
	Proxy Group					
1	Atmos Energy	ATO	9.80%	TX	Jun-25	Atmos Energy - Texas
2	Chesapeake	CPK	9.60%	DE	Jun-25	Chesapeake Delaware
3	NiSource	NI	9.75%	KY	May-25	Columbia Gas of Kentucky
4	New Jersey Resources	NJR	9.60%	NJ	Nov-24	New Jersey Natural Gas
5	Northwest Natural Holdings	NWN	9.40%	OR	Oct-24	Northwest Natural Gas
6	One Gas	OGS	9.70%	TX	Nov-24	Texas Gas Service
7	WEC Energy Group	WEC	9.80%	WI	Dec-25	Wisc Elec., Wisc. Gas, WPSC
9	**Average of seven companies**		**9.66%**			

* Regulatory Research Associates

MPSC Case No: U-21973
Requester: Staff
Question No.: JEU-1.1
Respondent: T. J. Lepczyk
Page: 1 of 1

Question: Please provide the most recent Credit Opinion from S&P, Moody's, and Fitch for DTE Gas.

Answer: See attachment labeled "U-21973 JEU-1.1-01 S&P DTE Gas Company 2025", "U-21973 JEU-1.1-02 Moody's DTE Gas Company 2025", and "U-21973 JEU-1.1-03 Fitch DTE Gas Company 2025".

Attachment: U-21973 JEU-1.1-01 S&P DTE Gas Company 2025
U-21973 JEU-1.1-02 Moody's DTE Gas Company 2025
U-21973 JEU-1.1-03 Fitch DTE Gas Company 2025

THE FOLLOWING 22 PAGES INCLUDE THE MOODY'S AND S&P CREDIT REPORTS

MOODY'S RATINGS

CREDIT OPINION
17 July 2025

Update

Send Your Feedback

RATINGS

DTE Gas Company

Domicile	Detroit, Michigan, United States
Long Term Rating	A3
Type	Senior Unsecured Bank Credit Facility - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

DTE Gas Company

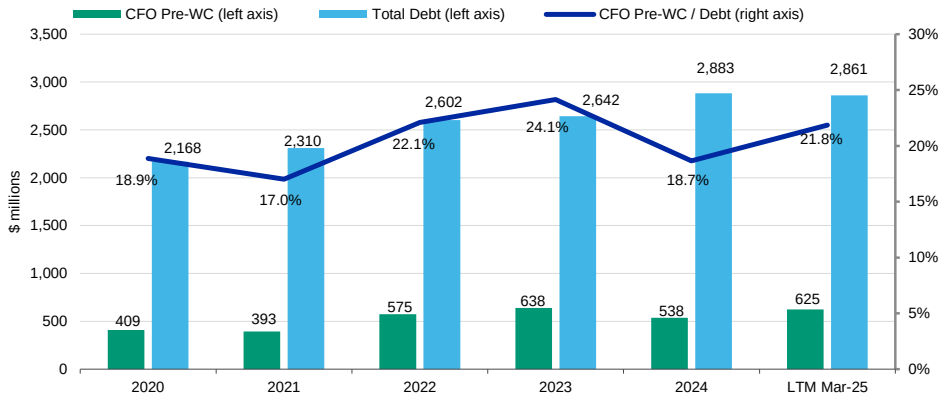
Update to credit analysis

Summary

DTE Gas Company's (DTE Gas, A3 stable) credit profile incorporates its low business risk profile as a regulated natural gas local distribution company (LDC), and a credit supportive regulatory environment in Michigan.

We expect the company's cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio to be maintained in the high-teens despite sustained higher capital expenditures. This metric for the last twelve month (LTM) period ending 31 March 2025 was higher, at 21.8%, due to an increase in the recovery of historical natural gas costs. Over the next 2-3 years, the company's debt is likely to increase in order to partially fund its capital expenditures and to maintain a 50% equity capital structure. However, we expect DTE Gas to also steadily increase its cash flow generation under the constructive Michigan regulatory framework, maintaining its financial profile.

Exhibit 1
Historical CFO pre-WC, Total Debt and CFO pre-WC to Debt



All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Credit strengths

» Low risk business profile as a regulated gas LDC

» Credit supportive regulatory environment in Michigan

Credit challenges

» Sustained elevated capital investments

» Maintaining continued regulatory support amid a robust capital investment program

Rating outlook

The stable outlook reflects our expectation that the Michigan legislative and regulatory environment will remain credit supportive, and enable DTE Gas to recover prudently incurred capital investments on a timely basis. Also, the stable outlook incorporates our expectation that DTE Gas will continue to produce consistent and predictable financial metrics.

Factors that could lead to upgrade

A rating upgrade could be considered if there are legislative or other actions that improve timeliness of cost recovery, or if the regulatory environment in Michigan becomes even more formulaic and transparent. Also, a rating upgrade could be possible if DTE Gas's financial metrics improve such that its CFO pre-WC to debt ratio is above 19% on a sustained basis.

Factors that could lead to downgrade

A downgrade could be considered if the DTE Gas's financial profile deteriorates such that its CFO pre-WC to debt ratio falls to 16% or below on a sustained basis. Also, if there is an adverse change in the Michigan regulatory environment or if the company experiences insufficient cost recovery or returns, a rating downgrade could be possible.

Key indicators

Exhibit 2

DTE Gas Company

	2020	2021	2022	2023	2024	LTM Mar-25
CFO Pre-W/C + Interest / Interest	6.1x	5.8x	7.2x	7.2x	5.5x	6.1x
CFO Pre-W/C / Debt	18.9%	17.0%	22.1%	24.1%	18.7%	21.8%
CFO Pre-W/C – Dividends / Debt	12.6%	10.6%	15.8%	16.9%	11.4%	14.4%
Debt / Capitalization	43.9%	43.5%	44.5%	42.3%	42.2%	40.8%

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months.
Source: Moody's Financial Metrics™

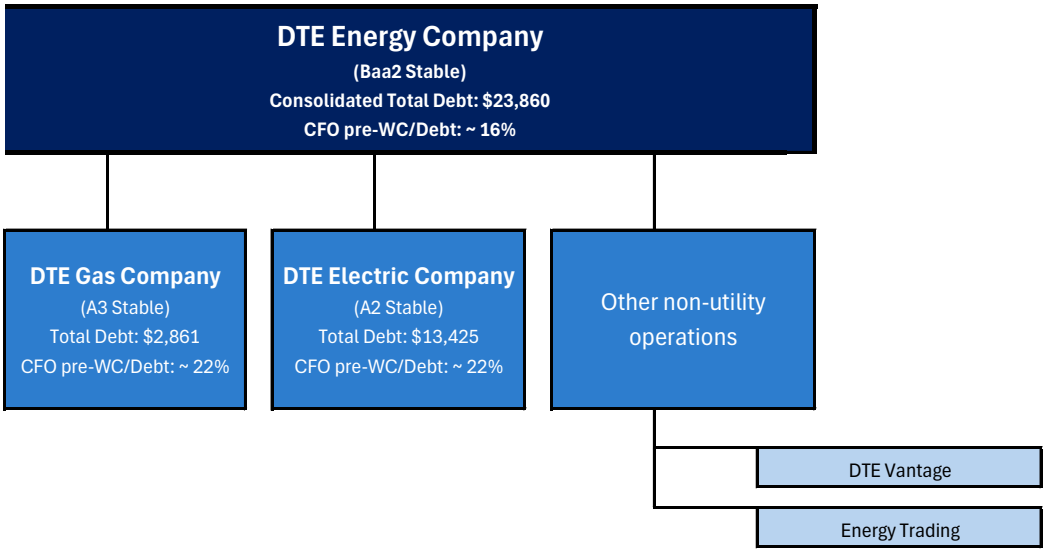
Profile

DTE Gas is a gas distribution utility subsidiary of DTE Energy Company (DTE, Baa2 stable) and is regulated by the Michigan Public Service Commission (MPSC). DTE Gas serves approximately 1.3 million residential, commercial and industrial customers throughout Michigan, with approximately $6.9 billion in rate base (~23% of DTE's total state jurisdictional rate base).

Exhibit 3

Organizational Chart

Total debt as adjusted ($ millions)

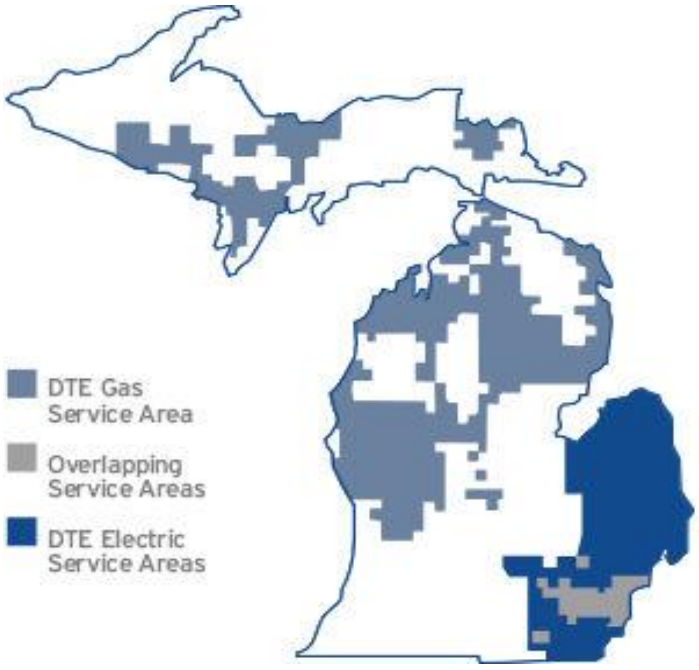


All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months. Total adjusted debt as of 31 March 2025.

Sources: Moody's Financial Metrics™ and Company filings

Exhibit 4

DTE Service Area Map



Source: Company filings

Detailed credit considerations

Credit supportive regulatory environment in Michigan

DTE Gas is regulated by the MPSC, which has a regulatory framework that we view as more credit supportive than most other states. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework was streamlined, improving both the rate case process and the timeliness of cost recovery. In accordance with the 2016 legislation, utility rate cases are able to be filed on a forward

test year basis but must now be decided within ten months (reduced from twelve) of the date of filing. The offset to a faster rate process was the loss of the ability to self implement rates after six months.

Importance of maintaining continued regulatory support

DTE Gas benefits from several automatic adjustment mechanisms including a forward-looking gas cost recovery (GCR) mechanism and a revenue decoupling mechanism (RDM) intended to adjust for the impacts of customer conservation efforts. The MPSC also approved an infrastructure recovery mechanism (IRM) to allow recovery of the costs related to annual investments in main renewal, meter relocation, and pipeline integrity.

DTE Gas's latest general rate case concluded in February 2025 when the MPSC granted a request for rehearing of the rate case and authorized modest additional gas rate increase. The rate case was initially concluded in November 2024 when the MPSC authorized a $114 million revenue increase, excluding new depreciation rates and OPEB impact, based on a 9.8% return on equity (ROE) and $6.889 billion of forward rate base. This rate case was fully litigated and the final authorized increase was meaningfully lower than the company's initial request of $265.5 million. While the rate increase was about half of the company's initial request, there were other aspects of the rate case outcome we viewed to be credit supportive. The MPSC approved the continuation of the IRM to recover a significant portion of the capital plan, a credit positive. The commission also approved the continuation of the RDM. Based on the current regulatory framework and our expectation that the regulatory environment in Michigan remains credit supportive, we estimate DTE Gas's CFO pre-WC to debt ratio to be in the 17% - 19% range over the next 2-3 years.

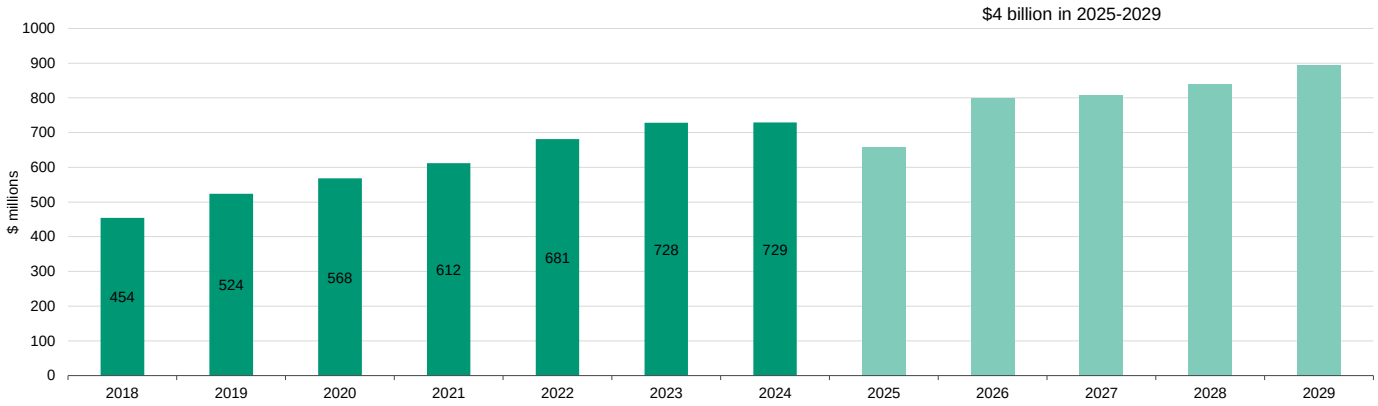
Maintaining a constructive relationship with the regulator and other stakeholders is becoming more important as the company continues to invest heavily and needs to manage the impact on the customers' bill. We note that either a deterioration of the allowed ROE or disallowance of cost recovery is likely to put negative pressure on the company's overall financial profile.

Elevated capital spending through 2029

DTE Gas's capital investment continues to be robust. The company increased its five-year investment plan through 2029 to $4 billion from $3.7 billion between 2024 and 2028. The increase was primarily related to the company's base infrastructure spending, which will enhance transmission, compression, distribution and storage of natural gas. These investments will remain high over the next five years as the utility focuses on its MPSC approved accelerated and expanded infrastructure renewal program for main replacement as well as some additional expenditures for its base infrastructure.

Exhibit 5

DTE Gas Historical and Pro Forma Capital Expenditures



Source: Company filings

Overall stable financial profile

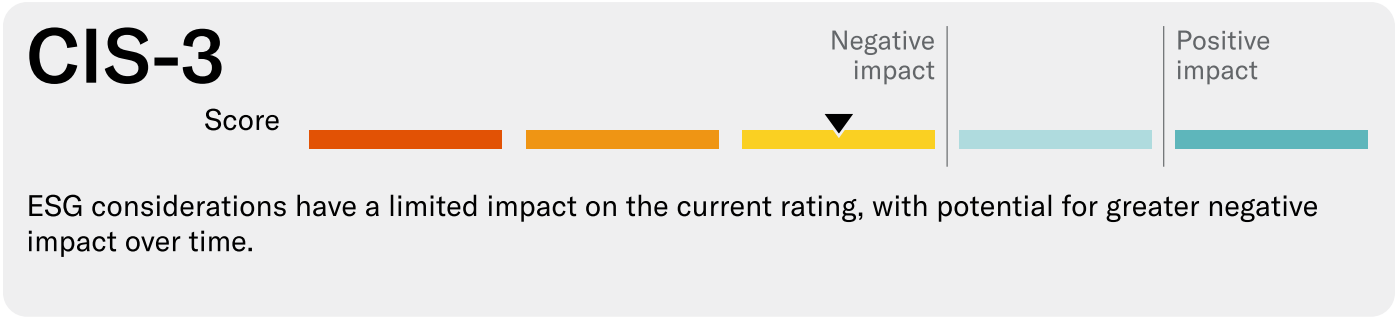
The overall credit profile of DTE Gas has improved since the delay in the recovery of the gas purchased cost pressured its CFO pre-WC to debt in 2021. Despite its robust capital expenditure over the next few years, we expect DTE Gas to maintain a relatively stable financial profile with CFO pre-WC to debt ranging at least 17% - 19%. The company continues to invest to replace its aging infrastructure, ensuring the reliability of its existing natural gas pipelines and improving its infrastructure to focus on opportunities for

decarbonization. Although its elevated investment program will increase its debt, the company should be able to generate consistently higher cash flow at the same time under the Michigan regulatory framework.

ESG considerations

DTE Gas Company's ESG credit impact score is CIS-3

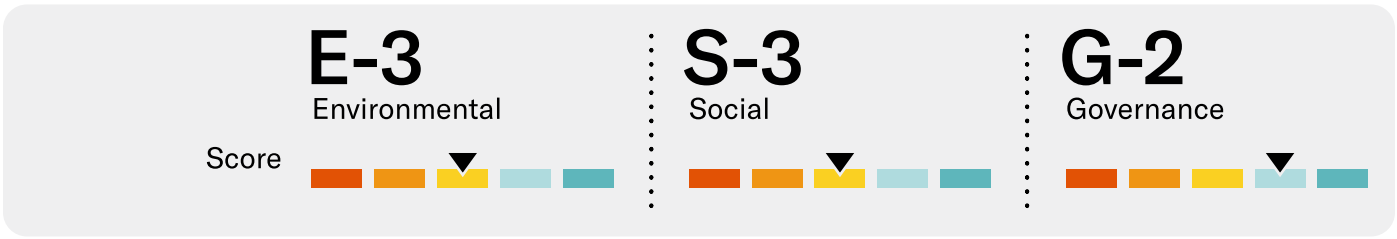
Exhibit 6
ESG credit impact score



Source: Moody's Ratings

DTE Gas's **CIS-3** indicates that its ESG attributes are overall considered to have limited impact on the current credit rating, with greater potential for future negative impact over time. It incorporates risks associated with moderate carbon transition risk and some risks related to demographic and societal trends connected to utility operations.

Exhibit 7
ESG issuer profile scores



Source: Moody's Ratings

Environmental

DTE Gas's **E-3** issuer profile score reflects its moderate carbon transition risk, including potential for methane leakage, although it does not have direct exposure to fossil-fueled generation as a natural gas local distribution company (LDC). It also incorporates moderately negative exposure to physical climate risks.

Social

DTE Gas's **S-3** issuer profile score is primarily related to the company's customer and regulatory relations as well as demographic and societal trends that could impact public concerns over affordability and utility's reputational risk. These pressures could turn into adverse political intervention or regulatory response.

Governance

DTE Gas's **G-2** issuer profile score reflects our view that its governance does not pose a particular risk.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

We expect DTE Gas' liquidity profile to be adequate over the next 12 months.

The company maintains a $300 million credit facility expiring in October 2029 that is primarily used to backstop its $300 million commercial paper program. The credit facility has no material adverse change clause for new borrowings, and contains one financial covenant that requires a maximum debt to capital ratio of 65%. As of 31 March 2025, the company was in compliance with the covenant with a reported ratio of 48%. Further supplementing DTE Gas' liquidity is the company's access to intercompany loans from its parent company, DTE.

The company's liquidity can be volatile due to the seasonal nature of gas demand and changes in gas prices. Its short-term borrowings tend to peak as it builds gas inventory before the winter high usage period. As of 31 March 2025, DTE Gas had no cash on its balance sheet and the full amount was available under its bank revolving credit facility.

For the last twelve months ending 31 March 2025, DTE Gas generated $525 million of cash from operations, invested $692 million in capital investments, and upstreamed $212 million in dividend payments to its parent, resulting in negative free cash flow of approximately $379 million. The company funded this negative free cash flow with incremental long-term debt. We anticipate that DTE Gas will continue to generate negative free cash flow balances given its robust capital investment plan. We expect that the negative free cash flow will continue to be funded via a combination of long and short term capital sources, including equity contributions from its parent. DTE Gas has received equity contributions from DTE every year, albeit in varying amounts. In 2023 and 2024, capital contributions from the parent were $216 million and $221 million, respectively. We expect parent equity contributions to continue over the next 2-3 years.

DTE Gas has $70 million of first mortgage bonds expiring in December 2025.

Methodology and scorecard

As a natural gas local distribution company (LDC) that does not have generation, DTE Gas is scored under the low business risk financial metric grid in the Regulated Electric and Gas Utilities methodology. The two notch difference between the scorecard-indicated outcome in the LTM ending 31 March 2025 and the actual rating is due to higher historical credit metrics resulting from the recover of historical natural gas cost.

Exhibit 8

Methodology scorecard factors

DTE Gas Company

Regulated Electric and Gas Utilities Industry Scorecard	Current LTM Mar-25		Moody's 12-18 month forward view	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	na	na	na	na
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.5x	Aa	5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	23.0%	A	17% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.5%	A	10% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	39.9%	Aa	42% - 44%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A1		A2
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		A1		A2
b) Actual Rating Assigned				A3

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months. Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Appendix

Exhibit 9

Peer comparison

DTE Gas Company

	DTE Gas Company A3 Stable			Northern Illinois Gas Company A2 Stable			Consumers Energy Company A3 Stable			Piedmont Natural Gas Company, Inc. A3 Stable			South Jersey Gas Company A3 Stable		
	FY	FY	LTM	FY	FY	LTM	FY	FY	LTM	FY	FY	LTM	FY	FY	FY
(in $ millions)	Dec-23	Dec-24	Mar-25	Dec-23	Dec-24	Mar-25	Dec-23	Dec-24	Mar-25	Dec-23	Dec-24	Mar-25	Dec-21	Dec-22	Dec-23
Revenue	1,726	1,783	1,946	2,593	2,326	2,372	7,166	7,200	7,451	1,628	1,729	1,910	618	825	738
CFO Pre-W/C	638	538	625	832	703	582	2,190	2,344	2,379	624	708	749	226	256	208
Total Debt	2,642	2,883	2,861	2,902	2,954	2,782	11,449	12,346	12,241	4,218	4,751	4,588	1,260	1,236	1,246
CFO Pre-W/C + Interest / Interest	7.2x	5.5x	6.1x	10.5x	7.7x	6.5x	5.8x	5.5x	5.5x	4.8x	4.8x	5.0x	6.0x	6.5x	4.3x
CFO Pre-W/C / Debt	24.1%	18.7%	21.8%	28.7%	23.8%	20.9%	19.1%	19.0%	19.4%	14.8%	14.9%	16.3%	17.9%	20.7%	16.7%
CFO Pre-W/C – Dividends / Debt	16.9%	11.4%	14.4%	18.3%	23.8%	20.9%	13.0%	12.5%	12.9%	14.8%	12.6%	13.9%	17.9%	20.7%	14.7%
Debt / Capitalization	42.3%	42.2%	40.8%	43.1%	41.0%	38.6%	45.8%	46.0%	45.3%	45.8%	46.9%	44.8%	39.6%	36.6%	35.7%

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Exhibit 10

Moody's-adjusted cash flow reconciliation

DTE Gas Company

(in $ millions)	2020	2021	2022	2023	2024	LTM Mar-25
FFO	**397.0**	**416.0**	**528.0**	**543.0**	**552.0**	**627.0**
+/- Other	12.0	(23.0)	47.0	95.0	(14.0)	(2.0)
CFO Pre-WC	**409.0**	**393.0**	**575.0**	**638.0**	**538.0**	**625.0**
+/- ΔWC	11.0	17.0	(96.0)	39.0	(77.0)	(100.0)
CFO	**420.0**	**410.0**	**479.0**	**677.0**	**461.0**	**525.0**
- Div	135.0	148.0	164.0	191.0	210.0	212.0
- Capex	568.0	612.0	681.0	728.0	729.0	692.0
FCF	**(283.0)**	**(350.0)**	**(366.0)**	**(242.0)**	**(478.0)**	**(379.0)**
(CFO Pre-W/C) / Debt	18.9%	17.0%	22.1%	24.1%	18.7%	21.8%
(CFO Pre-W/C - Dividends) / Debt	12.6%	10.6%	15.8%	16.9%	11.4%	14.4%
FFO / Debt	18.3%	18.0%	20.3%	20.6%	19.1%	21.9%
RCF / Debt	12.1%	11.6%	14.0%	13.3%	11.9%	14.5%
Revenue	1,396.0	1,532.0	1,894.0	1,726.0	1,783.0	1,946.0
Interest Expense	80.5	81.8	92.6	103.5	119.1	121.9
Net Income	197.6	222.5	275.9	279.4	248.6	302.2
Total Assets	6,366.0	6,692.0	7,279.0	7,660.0	8,394.0	8,679.0
Total Liabilities	4,293.5	4,457.0	4,877.0	4,939.0	5,403.0	5,538.0
Total Equity	2,072.5	2,235.0	2,402.0	2,721.0	2,991.0	3,141.0

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Ratings

Exhibit 11

Category	Moody's Rating
DTE GAS COMPANY	
Outlook	Stable
First Mortgage Bonds	A1
Senior Secured	A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
ULT PARENT: DTE ENERGY COMPANY	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Commercial Paper	P-2

Source: Moody's Ratings

REPORT NUMBER 1451155

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

S&P Global
Ratings

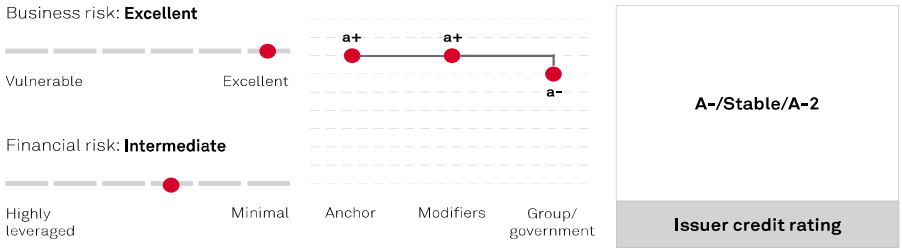
Research

DTE Gas Co.

October 2, 2025

This report does not constitute a rating action.

Ratings Score Snapshot



Credit Highlights

Overview

Key strengths	Key risks
Fully regulated, low-risk natural gas distribution utility.	Elevated capital spending for infrastructure investments.
Primarily residential customer base provides cash flow stability.	Lack of geographic and regulatory diversity makes DTEG dependent on its regulator the Michigan Public Service Commission (MPSC) to sustain credit quality.
Constructive regulatory environment, including timely cost and investment recovery, supports credit metrics.	Continued negative discretionary cash flow indicates external funding needs.

DTE Gas Co.'s (DTEG's) previous rate case outcome was less than favorable. In November 2024, the Michigan Public Service Commission (MPSC) approved a $113.8 million rate increase (revised upward to $115.6 million in February 2025), which included the roll-in of about $106 million of existing rider recovery into base rates, resulting in only about an $8 million net increase to EBITDA. This was well below the $266 million increase DTEG requested in January 2024. The approved settlement also reflected a slightly lower authorized return on equity of 9.8% versus 9.9% previously, along with several nonapproved cost items, including approximately $88 million of operating expenses. Importantly, most of the nonapproved costs relate to proposed expenses,

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giving the forward-looking rate making construct in Michigan. As a result, we expect DTEG will reduce its proposed expenditures accordingly, and maintain credit metrics consistent with its current rating, supported by its various cost recovery mechanisms embedded in Michigan's generally constructive regulatory framework. Overall, we expect funds from operations (FFO) to debt between 17% and 19% over the forecast period, consistent with its current financial risk profile assessment of intermediate.

We continue to assess DTEG's business risk profile as excellent. This reflects its very low-risk, regulated gas utility operations, very large customer base, and effective regulatory risk management. Somewhat offsetting these benefits is DTEG's limited geographic and regulatory diversity, given that it only operates in Michigan. However, we believe the utility's large, diverse base of 1.3 million customers and constructive regulation in Michigan mitigates this lack of diversity.

We continue to assess DTEG as an insulated subsidiary of DTE Energy Co. We rate DTEG one notch higher than our 'bbb+' group credit profile because of the strength of its stand-alone credit profile and our view of its financially separate status from the group in terms of its performance, funding arrangements, and operational independence.

Outlook

The stable rating outlook on DTEG reflects our base case assumption that it will generate sufficient cash flow to maintain appropriate financial measures for the current rating, including stand-alone FFO to debt of 17%-19% from 2025-2027. The outlook also reflects our expectation DTE Energy Co.'s management will remain focused on its core utility operations and maintain the company's current credit measures.

Downside scenario

We could lower our rating on DTEG over the next 24 months if we lower our rating on its parent, DTE Energy Co., or if DTEG's stand-alone financial measures weakens such that its FFO to debt remains consistently below 11%.

Upside scenario

We could upgrade DTEG over the next 24 months if we upgrade DTE Energy and the company maintains its current stand-alone financial measures.

Our Base-Case Scenario

Assumptions

- Effective management of regulatory risk and continued cost management enable the company's regulated operations to earn their allowed ROE;
- Revenue increases on customer- and volume-related growth, as well as expansion projects entering into service;
- Annual capital spending averaging about $750 million for the next three years;
- DTEG continues to use supportive regulatory mechanisms;
- Annual dividend payments average about $235 million for the next three years; and

- DTEG refinances all debt maturities.

Key metrics

DTE Gas Co.--Forecast summary

Period ending	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. $)	2023a	2024a	2025e	2026f	2027f
Adjusted ratios					
Debt/EBITDA (x)	3.8	4.4	4-5	4-5	4-5
FFO/debt (%)	21.1	17.7	17-19	17-19	17-19
FFO cash interest coverage (x)	6.8	5.7	5-6	5-6	5-6

All figures are adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. $--U.S. dollar.

Company Description

DTEG is a public utility that transports and distributes natural gas to about 1.3 million customers in Michigan. The company operates as a subsidiary of DTE Energy Co.

Peer Comparison

DTE Gas Co.--Peer Comparisons

	DTE Gas Co.	Wisconsin Gas LLC	ONE Gas Inc.	Northwest Natural Gas Co.
Foreign currency issuer credit rating	A-/Stable/A-2	A/Stable/A-1	A-/Stable/A-2	A+/Stable/A-1
Local currency issuer credit rating	A-/Stable/A-2	A/Stable/A-1	A-/Stable/A-2	A+/Stable/A-1
Period	Annual	Annual	Annual	Annual
Period ending	2024-12-31	2024-12-31	2024-12-31	2024-12-31
Mil.	$	$	$	$
Revenue	1,783	680	2,040	1,100
EBITDA	683	228	673	341
Funds from operations (FFO)	532	297	550	239
Interest	130	46	140	69
Cash interest paid	113	39	144	63
Operating cash flow (OCF)	460	297	337	232
Capital expenditure	728	223	695	354
Free operating cash flow (FOCF)	(268)	74	(357)	(122)
Discretionary cash flow (DCF)	(478)	(6)	(508)	(196)
Cash and short-term investments	0	0	58	20
Gross available cash	0	0	58	20
Debt	3,009	1,055	2,844	1,635
Equity	2,991	1,257	3,105	1,324
EBITDA margin (%)	38.3	33.5	33.0	30.9
Return on capital (%)	8.1	6.0	6.9	6.9

DTE Gas Co.--Peer Comparisons

EBITDA interest coverage (x)	5.3	5.0	4.8	4.9
FFO cash interest coverage (x)	5.7	8.6	4.8	4.8
Debt/EBITDA (x)	4.4	4.6	4.2	4.8
FFO/debt (%)	17.7	28.1	19.3	14.6
OCF/debt (%)	15.3	28.2	11.9	14.2
FOCF/debt (%)	(8.9)	7.0	(12.6)	(7.4)
DCF/debt (%)	(15.9)	(0.6)	(17.9)	(12.0)

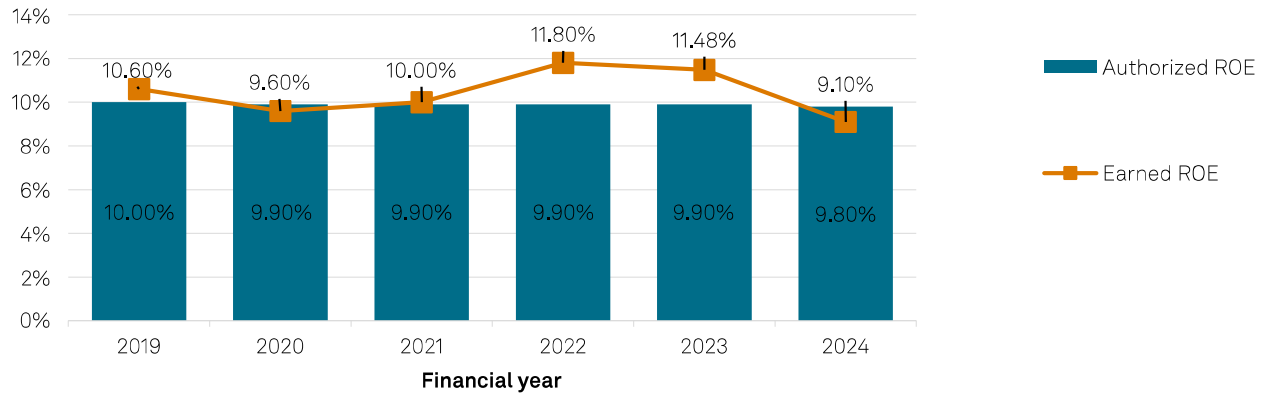
Business Risk

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. DTEG also operates under a revenue decoupling mechanism that supports cash flow stability.

Somewhat offsetting these benefits is DTEG's limited geographic and regulatory diversity, given that it only operates in Michigan. However, we believe the utility's large, diverse base of 1.3 million customers and constructive regulation mitigate this. The predominance of residential and commercial customers limits its susceptibility to economic cyclicality, further supporting our expectation for stable cash flows. Overall, we assess DTEG in the upper half of its business risk profile category compared with peers.

DTE Gas Co.'s return on equity*

Authorized versus earned ROE



Source: S&P Global Ratings.

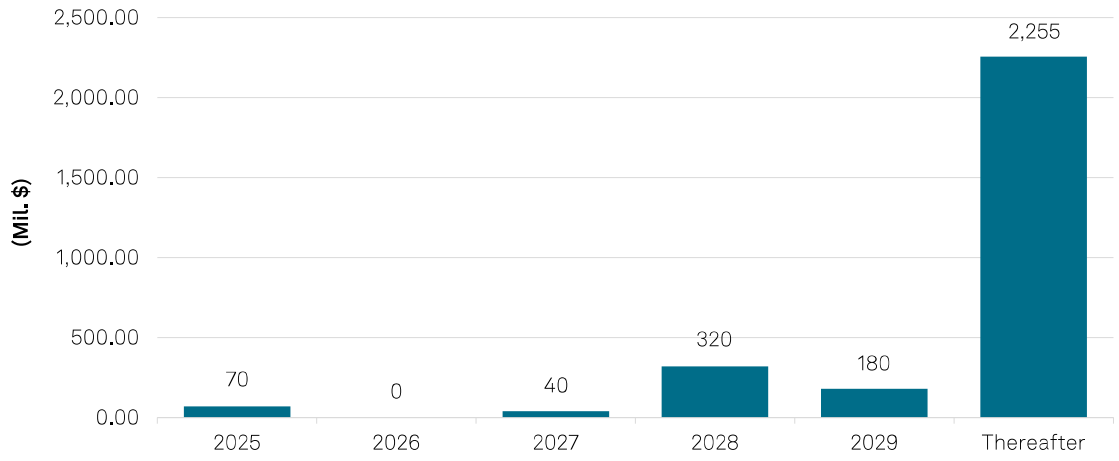
Financial Risk

We assess DTEG's financial risk profile using our low volatility table rather than the benchmark tables we use for typical corporate issuers. This is due to its low-risk, regulated utility business model and effective management of regulatory risk compared with its peers. Our assessment also reflects our stand-alone base case, which includes S&P Global Ratings-adjusted FFO to debt of about 17%-19% through our forecast period and a need for external funding due to consistently negative discretionary cash flow (after accounting for the utility's capital spending and dividend payments). Overall, our base case assumes DTEG will continue to effectively manage regulatory risk, with consistent and timely recovery of its capital expenditure and costs such that its financial risk profile does not materially deviate from our base-case expectations.

Debt maturities

DTE Gas Co.'s debt maturities

As of Dec. 31, 2024



Source: DTE Gas Co.'s annual report 2024.

DTE Gas Co.--Financial Summary

Period ending	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024
Reporting period	2019a	2020a	2021a	2022a	2023a	2024a
Display currency (mil.)	$	$	$	$	$	$
Revenues	1,462	1,396	1,532	1,894	1,726	1,783
EBITDA	478	494	531	654	699	683
Funds from operations (FFO)	401	416	452	575	568	532
Interest expense	88	90	90	102	114	130
Cash interest paid	75	77	79	86	98	113
Operating cash flow (OCF)	358	411	409	478	676	460

DTE Gas Co.--Financial Summary

Capital expenditure	523	567	611	680	727	728
Free operating cash flow (FOCF)	(165)	(156)	(202)	(202)	(51)	(268)
Discretionary cash flow (DCF)	(287)	(291)	(350)	(366)	(242)	(478)
Cash and short-term investments	1	0	1	0	0	0
Gross available cash	1	0	1	0	0	0
Debt	1,987	2,162	2,364	2,675	2,688	3,009
Common equity	1,852	2,023	2,235	2,402	2,721	2,991
Adjusted ratios						
EBITDA margin (%)	32.7	35.4	34.7	34.5	40.5	38.3
Return on capital (%)	8.7	7.7	7.7	9.5	9.5	8.1
EBITDA interest coverage (x)	5.4	5.5	5.9	6.4	6.1	5.3
FFO cash interest coverage (x)	6.3	6.4	6.7	7.7	6.8	5.7
Debt/EBITDA (x)	4.2	4.4	4.5	4.1	3.8	4.4
FFO/debt (%)	20.2	19.2	19.1	21.5	21.1	17.7
OCF/debt (%)	18.0	19.0	17.3	17.9	25.1	15.3
FOCF/debt (%)	(8.3)	(7.2)	(8.5)	(7.6)	(1.9)	(8.9)
DCF/debt (%)	(14.4)	(13.5)	(14.8)	(13.7)	(9.0)	(15.9)

Reconciliation Of DTE Gas Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2024									
Company reported amounts	2,877	2,991	1,783	662	438	118	683	461	210	729
Cash taxes paid	-	-	-	-	-	-	(38)	-	-	-
Cash interest paid	-	-	-	-	-	-	(112)	-	-	-
Capitalized interest	-	-	-	-	-	1	(1)	(1)	-	(1)
Share-based compensation expense	-	-	-	10	-	-	-	-	-	-
Asset-retirement obligations	156	-	-	11	11	11	-	-	-	-
Nonoperating income (expense)	-	-	-	-	15	-	-	-	-	-
Debt: other	(24)	-	-	-	-	-	-	-	-	-
Total adjustments	132	-	-	21	26	12	(151)	(1)	-	(1)
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	3,009	2,991	1,783	683	464	130	532	460	210	728

Liquidity

As of June 30, 2025, we assess DTEG's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecast consolidated EBITDA declines 10%. We believe the supportive regulatory framework provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity.

In addition, DTEG can absorb high-impact, low-probability events. The company maintains about $300 million in committed credit facilities through 2029, and we believe the company can lower its capital spending (averaging about $750 million annually over the next three years), indicating a limited need for refinancing when stressed. Furthermore, our assessment reflects the company has prudent risk management and sound relationships with its banking group.

Overall, we believe the company can withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The next major debt maturity for the company is in 2028.

Principal liquidity sources

- Minimal cash on balance sheet;
- Estimated cash FFO of about $600 million; and
- Revolving credit facility availability of about $300 million.

Principal liquidity uses

- Debt maturities of about $70 million over the next 12 months;
- Assumed maintenance capital spending of about $500 million; and
- Dividends of about $230 million.

Environmental, Social, And Governance

ESG factors have no material influence on our credit rating analysis of DTEG.

Group Influence

We assess DTEG to be a core subsidiary of DTE Energy Co., which reflects our view that it benefits from a strong, long-term commitment from senior management, is integral to the group's strategy, and is highly unlikely to be sold. We view DTEG as insulated from its parent. This means we expect any significant credit stress at DTE Energy would not unduly impair the creditworthiness of the subsidiary.

We rate DTEG one notch higher than our 'bbb+' group credit profile because of the strength of its stand-alone credit profile and our view of how financially separate it is from the group in terms of its performance, funding arrangements, and operational independence. DTEG maintains its own records and funding arrangements and does not commingle funds, assets, or cash flows. In addition, because it is an independent regulated utility, we believe there is a strong economic incentive for its parent to preserve its credit strength. We do not expect that a default by either DTE Energy or another entity in the group would lead to a default at DTEG.

Issue Ratings--Subordination Risk Analysis

Analytical conclusions

We base our 'A-2' short-term rating on our long-term issuer credit rating on DTEG.

Issue Ratings--Recovery Analysis

Key analytical factors

DTEG's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue-level rating of 'A', which is one notch above the long-term issuer credit rating.

Rating Component Scores	
Foreign currency issuer credit rating	**A-/Stable/A-2**
Local currency issuer credit rating	**A-/Stable/A-2**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Intermediate**
Cash flow/leverage	Intermediate
Anchor	**a+**
Modifiers	
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a+**
Group Credit Profile	**bbb+**
Entity Status Within Group	**Core (-2 notch from SACP)**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, July 7 2025
- General Criteria: Hybrid Capital: Methodology And Assumptions, Feb. 10 2025
- Criteria | Corporates | General: Corporate Methodology, Jan. 7 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10 2021

- General Criteria: Group Rating Methodology, July 1 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7 2017
- Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19 2013
- General Criteria: Methodology: Industry Risk, Nov. 19 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16 2011

Ratings Detail (as of October 01, 2025)*

DTE Gas Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Issuer Credit Ratings History	
27-Aug-2019	A-/Stable/A-2
21-Aug-2015	BBB+/Stable/A-2
19-Aug-2013	BBB+/Positive/A-2
Related Entities	
DTE Electric Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Senior Secured	A/A-2
DTE Energy Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated	BBB-
Senior Unsecured	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

MPSC Case No: U-21973
Requester: Staff
Question No.: JEU-1.1
Respondent: T. J. Lepczyk
Page: 1 of 1

Question: Please provide the most recent Credit Opinion from S&P, Moody's, and Fitch for DTE Gas.

Answer: See attachment labeled "U-21973 JEU-1.1-01 S&P DTE Gas Company 2025", "U-21973 JEU-1.1-02 Moody's DTE Gas Company 2025", and "U-21973 JEU-1.1-03 Fitch DTE Gas Company 2025".

Attachment: U-21973 JEU-1.1-01 S&P DTE Gas Company 2025
U-21973 JEU-1.1-02 Moody's DTE Gas Company 2025
U-21973 JEU-1.1-03 Fitch DTE Gas Company 2025

THE FOLLOWING 12 PAGES INCLUDE THE MOODY'S CREDIT REPORT

MOODY'S RATINGS

CREDIT OPINION
17 July 2025

Update

Send Your Feedback

RATINGS

DTE Gas Company

Domicile	Detroit, Michigan, United States
Long Term Rating	A3
Type	Senior Unsecured Bank Credit Facility - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

DTE Gas Company

Update to credit analysis

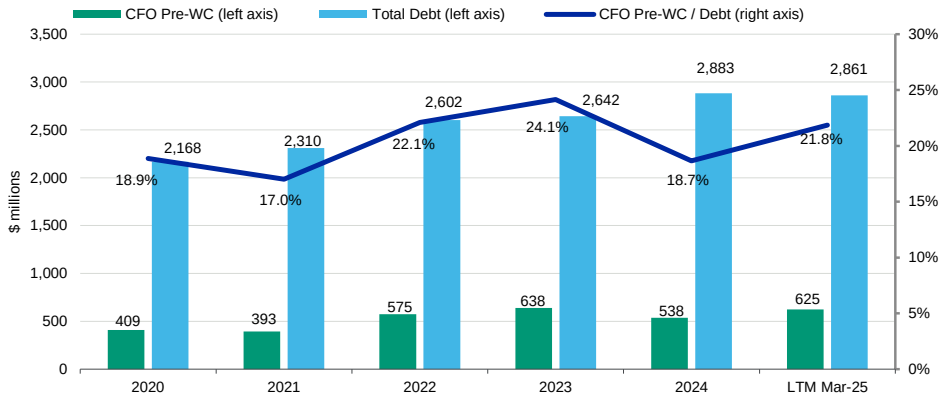
Summary

DTE Gas Company's (DTE Gas, A3 stable) credit profile incorporates its low business risk profile as a regulated natural gas local distribution company (LDC), and a credit supportive regulatory environment in Michigan.

We expect the company's cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio to be maintained in the high-teens despite sustained higher capital expenditures. This metric for the last twelve month (LTM) period ending 31 March 2025 was higher, at 21.8%, due to an increase in the recovery of historical natural gas costs. Over the next 2-3 years, the company's debt is likely to increase in order to partially fund its capital expenditures and to maintain a 50% equity capital structure. However, we expect DTE Gas to also steadily increase its cash flow generation under the constructive Michigan regulatory framework, maintaining its financial profile.

Exhibit 1

Historical CFO pre-WC, Total Debt and CFO pre-WC to Debt



All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Credit strengths

» Low risk business profile as a regulated gas LDC

» Credit supportive regulatory environment in Michigan

Credit challenges

» Sustained elevated capital investments

» Maintaining continued regulatory support amid a robust capital investment program

Rating outlook

The stable outlook reflects our expectation that the Michigan legislative and regulatory environment will remain credit supportive, and enable DTE Gas to recover prudently incurred capital investments on a timely basis. Also, the stable outlook incorporates our expectation that DTE Gas will continue to produce consistent and predictable financial metrics.

Factors that could lead to upgrade

A rating upgrade could be considered if there are legislative or other actions that improve timeliness of cost recovery, or if the regulatory environment in Michigan becomes even more formulaic and transparent. Also, a rating upgrade could be possible if DTE Gas's financial metrics improve such that its CFO pre-WC to debt ratio is above 19% on a sustained basis.

Factors that could lead to downgrade

A downgrade could be considered if the DTE Gas's financial profile deteriorates such that its CFO pre-WC to debt ratio falls to 16% or below on a sustained basis. Also, if there is an adverse change in the Michigan regulatory environment or if the company experiences insufficient cost recovery or returns, a rating downgrade could be possible.

Key indicators

Exhibit 2

DTE Gas Company

	2020	2021	2022	2023	2024	LTM Mar-25
CFO Pre-W/C + Interest / Interest	6.1x	5.8x	7.2x	7.2x	5.5x	6.1x
CFO Pre-W/C / Debt	18.9%	17.0%	22.1%	24.1%	18.7%	21.8%
CFO Pre-W/C – Dividends / Debt	12.6%	10.6%	15.8%	16.9%	11.4%	14.4%
Debt / Capitalization	43.9%	43.5%	44.5%	42.3%	42.2%	40.8%

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months.
Source: Moody's Financial Metrics™

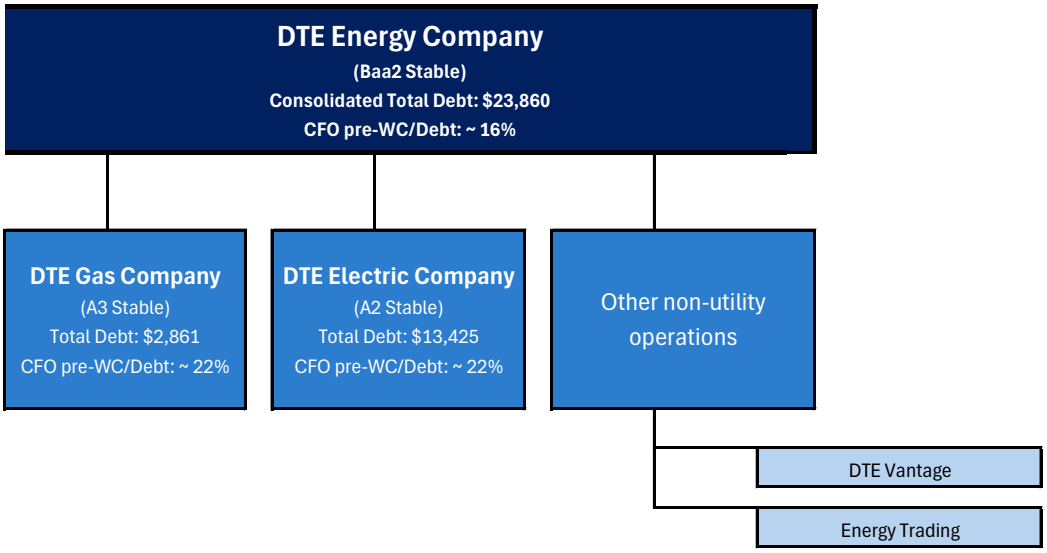
Profile

DTE Gas is a gas distribution utility subsidiary of DTE Energy Company (DTE, Baa2 stable) and is regulated by the Michigan Public Service Commission (MPSC). DTE Gas serves approximately 1.3 million residential, commercial and industrial customers throughout Michigan, with approximately $6.9 billion in rate base (~23% of DTE's total state jurisdictional rate base).

Exhibit 3

Organizational Chart

Total debt as adjusted ($ millions)

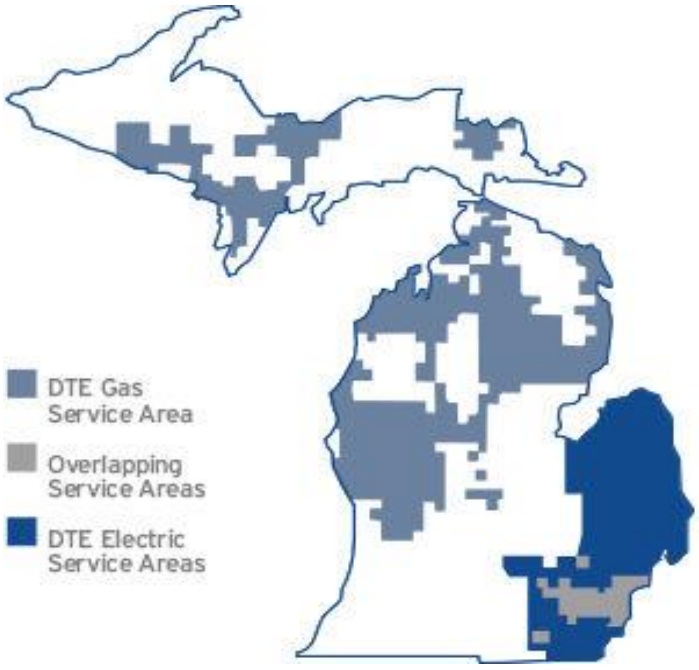


All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months. Total adjusted debt as of 31 March 2025.

Sources: Moody's Financial Metrics™ and Company filings

Exhibit 4

DTE Service Area Map



Source: Company filings

Detailed credit considerations

Credit supportive regulatory environment in Michigan

DTE Gas is regulated by the MPSC, which has a regulatory framework that we view as more credit supportive than most other states. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework was streamlined, improving both the rate case process and the timeliness of cost recovery. In accordance with the 2016 legislation, utility rate cases are able to be filed on a forward

test year basis but must now be decided within ten months (reduced from twelve) of the date of filing. The offset to a faster rate process was the loss of the ability to self implement rates after six months.

Importance of maintaining continued regulatory support

DTE Gas benefits from several automatic adjustment mechanisms including a forward-looking gas cost recovery (GCR) mechanism and a revenue decoupling mechanism (RDM) intended to adjust for the impacts of customer conservation efforts. The MPSC also approved an infrastructure recovery mechanism (IRM) to allow recovery of the costs related to annual investments in main renewal, meter relocation, and pipeline integrity.

DTE Gas's latest general rate case concluded in February 2025 when the MPSC granted a request for rehearing of the rate case and authorized modest additional gas rate increase. The rate case was initially concluded in November 2024 when the MPSC authorized a $114 million revenue increase, excluding new depreciation rates and OPEB impact, based on a 9.8% return on equity (ROE) and $6.889 billion of forward rate base. This rate case was fully litigated and the final authorized increase was meaningfully lower than the company's initial request of $265.5 million. While the rate increase was about half of the company's initial request, there were other aspects of the rate case outcome we viewed to be credit supportive. The MPSC approved the continuation of the IRM to recover a significant portion of the capital plan, a credit positive. The commission also approved the continuation of the RDM. Based on the current regulatory framework and our expectation that the regulatory environment in Michigan remains credit supportive, we estimate DTE Gas's CFO pre-WC to debt ratio to be in the 17% - 19% range over the next 2-3 years.

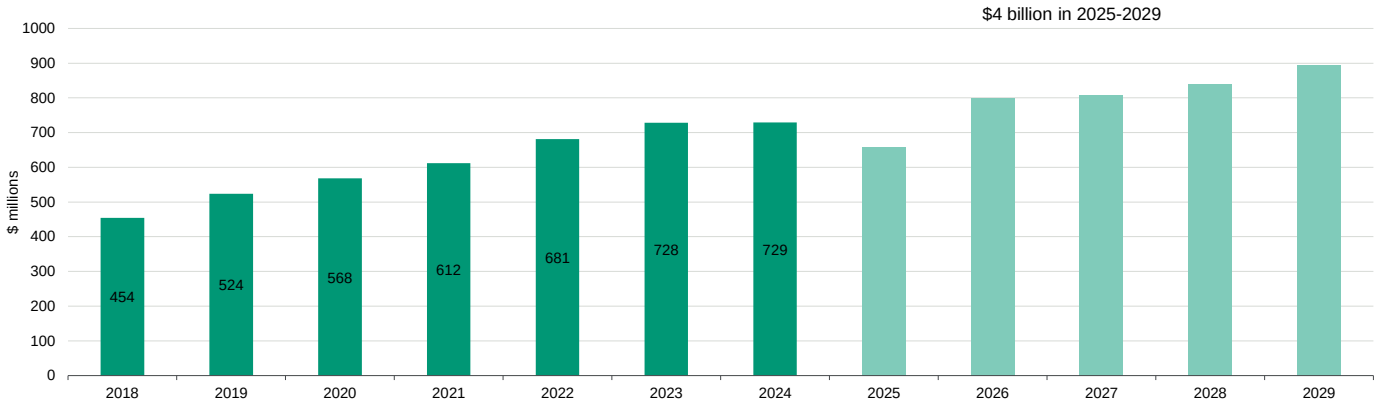
Maintaining a constructive relationship with the regulator and other stakeholders is becoming more important as the company continues to invest heavily and needs to manage the impact on the customers' bill. We note that either a deterioration of the allowed ROE or disallowance of cost recovery is likely to put negative pressure on the company's overall financial profile.

Elevated capital spending through 2029

DTE Gas's capital investment continues to be robust. The company increased its five-year investment plan through 2029 to $4 billion from $3.7 billion between 2024 and 2028. The increase was primarily related to the company's base infrastructure spending, which will enhance transmission, compression, distribution and storage of natural gas. These investments will remain high over the next five years as the utility focuses on its MPSC approved accelerated and expanded infrastructure renewal program for main replacement as well as some additional expenditures for its base infrastructure.

Exhibit 5

DTE Gas Historical and Pro Forma Capital Expenditures



Source: Company filings

Overall stable financial profile

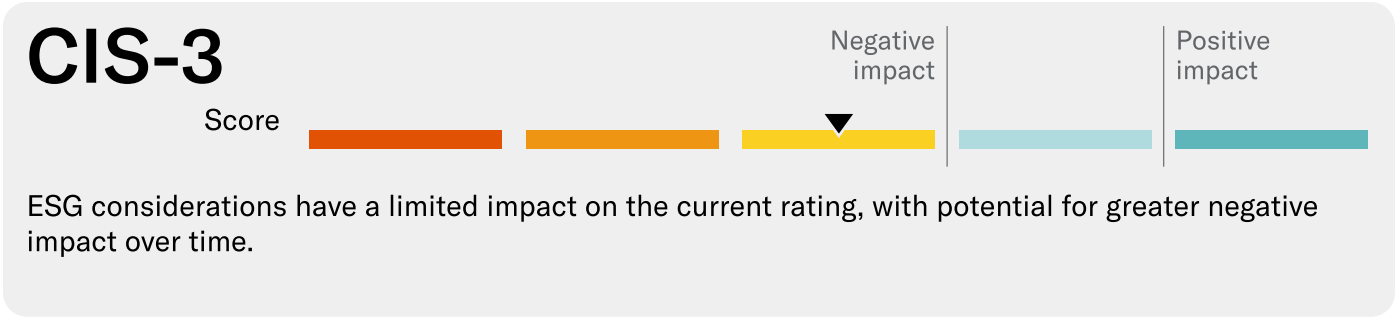
The overall credit profile of DTE Gas has improved since the delay in the recovery of the gas purchased cost pressured its CFO pre-WC to debt in 2021. Despite its robust capital expenditure over the next few years, we expect DTE Gas to maintain a relatively stable financial profile with CFO pre-WC to debt ranging at least 17% - 19%. The company continues to invest to replace its aging infrastructure, ensuring the reliability of its existing natural gas pipelines and improving its infrastructure to focus on opportunities for

decarbonization. Although its elevated investment program will increase its debt, the company should be able to generate consistently higher cash flow at the same time under the Michigan regulatory framework.

ESG considerations

DTE Gas Company's ESG credit impact score is CIS-3

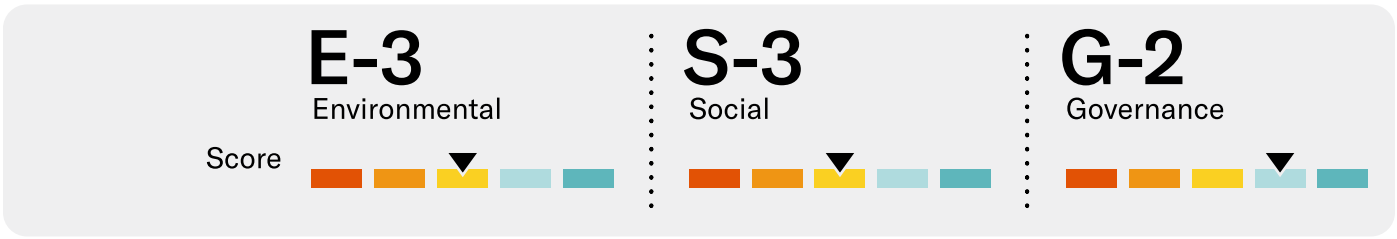
Exhibit 6
ESG credit impact score



Source: Moody's Ratings

DTE Gas's **CIS-3** indicates that its ESG attributes are overall considered to have limited impact on the current credit rating, with greater potential for future negative impact over time. It incorporates risks associated with moderate carbon transition risk and some risks related to demographic and societal trends connected to utility operations.

Exhibit 7
ESG issuer profile scores



Source: Moody's Ratings

Environmental

DTE Gas's **E-3** issuer profile score reflects its moderate carbon transition risk, including potential for methane leakage, although it does not have direct exposure to fossil-fueled generation as a natural gas local distribution company (LDC). It also incorporates moderately negative exposure to physical climate risks.

Social

DTE Gas's **S-3** issuer profile score is primarily related to the company's customer and regulatory relations as well as demographic and societal trends that could impact public concerns over affordability and utility's reputational risk. These pressures could turn into adverse political intervention or regulatory response.

Governance

DTE Gas's **G-2** issuer profile score reflects our view that its governance does not pose a particular risk.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

We expect DTE Gas' liquidity profile to be adequate over the next 12 months.

The company maintains a $300 million credit facility expiring in October 2029 that is primarily used to backstop its $300 million commercial paper program. The credit facility has no material adverse change clause for new borrowings, and contains one financial covenant that requires a maximum debt to capital ratio of 65%. As of 31 March 2025, the company was in compliance with the covenant with a reported ratio of 48%. Further supplementing DTE Gas' liquidity is the company's access to intercompany loans from its parent company, DTE.

The company's liquidity can be volatile due to the seasonal nature of gas demand and changes in gas prices. Its short-term borrowings tend to peak as it builds gas inventory before the winter high usage period. As of 31 March 2025, DTE Gas had no cash on its balance sheet and the full amount was available under its bank revolving credit facility.

For the last twelve months ending 31 March 2025, DTE Gas generated $525 million of cash from operations, invested $692 million in capital investments, and upstreamed $212 million in dividend payments to its parent, resulting in negative free cash flow of approximately $379 million. The company funded this negative free cash flow with incremental long-term debt. We anticipate that DTE Gas will continue to generate negative free cash flow balances given its robust capital investment plan. We expect that the negative free cash flow will continue to be funded via a combination of long and short term capital sources, including equity contributions from its parent. DTE Gas has received equity contributions from DTE every year, albeit in varying amounts. In 2023 and 2024, capital contributions from the parent were $216 million and $221 million, respectively. We expect parent equity contributions to continue over the next 2-3 years.

DTE Gas has $70 million of first mortgage bonds expiring in December 2025.

Methodology and scorecard

As a natural gas local distribution company (LDC) that does not have generation, DTE Gas is scored under the low business risk financial metric grid in the Regulated Electric and Gas Utilities methodology. The two notch difference between the scorecard-indicated outcome in the LTM ending 31 March 2025 and the actual rating is due to higher historical credit metrics resulting from the recover of historical natural gas cost.

Exhibit 8

Methodology scorecard factors

DTE Gas Company

Regulated Electric and Gas Utilities Industry Scorecard	Current LTM Mar-25		Moody's 12-18 month forward view	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	na	na	na	na
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.5x	Aa	5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	23.0%	A	17% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.5%	A	10% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	39.9%	Aa	42% - 44%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A1		A2
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		A1		A2
b) Actual Rating Assigned				A3

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months. Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Appendix

Exhibit 9

Peer comparison

DTE Gas Company

	DTE Gas Company A3 Stable			Northern Illinois Gas Company A2 Stable			Consumers Energy Company A3 Stable			Piedmont Natural Gas Company, Inc. A3 Stable			South Jersey Gas Company A3 Stable		
	FY	FY	LTM	FY	FY	LTM	FY	FY	LTM	FY	FY	LTM	FY	FY	FY
(in $ millions)	Dec-23	Dec-24	Mar-25	Dec-23	Dec-24	Mar-25	Dec-23	Dec-24	Mar-25	Dec-23	Dec-24	Mar-25	Dec-21	Dec-22	Dec-23
Revenue	1,726	1,783	1,946	2,593	2,326	2,372	7,166	7,200	7,451	1,628	1,729	1,910	618	825	738
CFO Pre-W/C	638	538	625	832	703	582	2,190	2,344	2,379	624	708	749	226	256	208
Total Debt	2,642	2,883	2,861	2,902	2,954	2,782	11,449	12,346	12,241	4,218	4,751	4,588	1,260	1,236	1,246
CFO Pre-W/C + Interest / Interest	7.2x	5.5x	6.1x	10.5x	7.7x	6.5x	5.8x	5.5x	5.5x	4.8x	4.8x	5.0x	6.0x	6.5x	4.3x
CFO Pre-W/C / Debt	24.1%	18.7%	21.8%	28.7%	23.8%	20.9%	19.1%	19.0%	19.4%	14.8%	14.9%	16.3%	17.9%	20.7%	16.7%
CFO Pre-W/C – Dividends / Debt	16.9%	11.4%	14.4%	18.3%	23.8%	20.9%	13.0%	12.5%	12.9%	14.8%	12.6%	13.9%	17.9%	20.7%	14.7%
Debt / Capitalization	42.3%	42.2%	40.8%	43.1%	41.0%	38.6%	45.8%	46.0%	45.3%	45.8%	46.9%	44.8%	39.6%	36.6%	35.7%

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Exhibit 10

Moody's-adjusted cash flow reconciliation

DTE Gas Company

(in $ millions)	2020	2021	2022	2023	2024	LTM Mar-25
FFO	**397.0**	**416.0**	**528.0**	**543.0**	**552.0**	**627.0**
+/- Other	12.0	(23.0)	47.0	95.0	(14.0)	(2.0)
CFO Pre-WC	**409.0**	**393.0**	**575.0**	**638.0**	**538.0**	**625.0**
+/- ΔWC	11.0	17.0	(96.0)	39.0	(77.0)	(100.0)
CFO	**420.0**	**410.0**	**479.0**	**677.0**	**461.0**	**525.0**
- Div	135.0	148.0	164.0	191.0	210.0	212.0
- Capex	568.0	612.0	681.0	728.0	729.0	692.0
FCF	**(283.0)**	**(350.0)**	**(366.0)**	**(242.0)**	**(478.0)**	**(379.0)**
(CFO Pre-W/C) / Debt	18.9%	17.0%	22.1%	24.1%	18.7%	21.8%
(CFO Pre-W/C - Dividends) / Debt	12.6%	10.6%	15.8%	16.9%	11.4%	14.4%
FFO / Debt	18.3%	18.0%	20.3%	20.6%	19.1%	21.9%
RCF / Debt	12.1%	11.6%	14.0%	13.3%	11.9%	14.5%
Revenue	1,396.0	1,532.0	1,894.0	1,726.0	1,783.0	1,946.0
Interest Expense	80.5	81.8	92.6	103.5	119.1	121.9
Net Income	197.6	222.5	275.9	279.4	248.6	302.2
Total Assets	6,366.0	6,692.0	7,279.0	7,660.0	8,394.0	8,679.0
Total Liabilities	4,293.5	4,457.0	4,877.0	4,939.0	5,403.0	5,538.0
Total Equity	2,072.5	2,235.0	2,402.0	2,721.0	2,991.0	3,141.0

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Ratings

Exhibit 11

Category	Moody's Rating
DTE GAS COMPANY	
Outlook	Stable
First Mortgage Bonds	A1
Senior Secured	A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
ULT PARENT: DTE ENERGY COMPANY	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Commercial Paper	P-2

Source: Moody's Ratings

REPORT NUMBER 1451155

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-1.9a
Respondent: T. J. Lepczyk
Page: 1 of 1

Question: Refer to Mr. Lepczyk's direct testimony on the capital structure. Please:

a. Identify which, if any, rating agencies have notified the Company that an equity ratio higher than 50% is required to maintain existing credit ratings. If so, provide a copy of the written notifications received from the rating agencies.

Answer: None of the rating agencies have notified us at this time that a higher equity ratio is required to maintain existing credit ratings. However, such a notification is not an appropriate measure, as the rating agencies are not required to notify us that a credit rating action will occur ahead of reporting the change. Ratings for DTE Gas are highly dependent on regulatory outcomes, and all the agencies will do a thorough review of our credit rating after the forthcoming order is received.

Further, Fitch stated in their March 2025 opinion on DTE Energy that a key assumption to their rating is a constructive regulatory environment in Michigan, with returns on equity for DTE Electric and DTE Gas in line with currently approved returns.

Attachment: None

Exhibit AG-34

CONFIDENTIAL

VLFAlert

ValueLinefunds

4th Quarter 2018

Volume VII, Issue IV

00207257

Mitchell Appel
President
Value Line Funds

Dear Fellow Shareholder,

Thank you for choosing Value Line Funds as a part of your diversified investment portfolio. For over half a century, Value Line Funds has championed sound investment principles and helped thousands of investors accomplish their financial goals with our actively managed family of mutual funds.

We hope you enjoy this edition of the VLFAlert and thank you for your continued support.

Volatility is Not Risk:
Why the Difference is Critical to Long-Term Results

2017 lulled many equity investors into a comfort zone based on historically low volatility. 2018 has been more volatile—with tighter monetary policy and geopolitical and trade policy uncertainty among the drivers of the increase. But volatility levels in 2018 are actually historically normal—even with the bouts of volatility anticipated ahead of the November mid-term elections. But volatility is not risk. And recognizing the difference can be critical to your long-term investment returns.

Defining Our Terms

Volatility is simply the measure of the up and down movements of the market. For example, since 1950, when the Value Line Funds were first established, the average maximum drawdown in the broad U.S. equity market during midterm election years has been -17%, with weakness tending to be concentrated in the pre-election days. However, the good news is that there has been a consistent tendency historically for post-drawdown rallies, averaging +32% in the subsequent year.[1] Volatility? Yes! Uncertainty? Yes! But volatility is only risk if you act during down times—that is, only if you sell. To which the often-invoked quip may well be the most prudent answer: "Don't just do something, sit there."

Risk, on the other hand, is the probability of a permanent loss. You might think of risk as the possibility of having to lower your quality of life in the future.

> **"Volatility is not synonymous of risk but—for those who truly understand it—of wealth."**
> *- Francois Rochon**

Recognizing the Difference

Volatility is independent of risk. Too many investors let an investment's short-term price movements, or perceptions of short-term price movements, drive their buying and selling decisions. Too often volatility is regarded as something to be avoided. But since short-term price moves are unknowable and independent of underlying fundamentals and value, such volatility should not be a determinant.

And ALL investments have risk of some kind, including cash and CDs. One just needs to pick the risks that are best to take based on your individual tolerance level, time horizon and financial needs and goals.

As famed investor and Berkshire Hathaway CEO Warren Buffet wrote:

> "Stock prices will always be far more *volatile* than cash-equivalent holdings. *Over the long term*, however, currency-denominated instruments are *riskier* investments — far riskier investments — than widely-diversified stock portfolios that are bought over time and that are owned in a manner invoking only token fees and commissions. **That lesson has not customarily been taught in business schools, where volatility is almost universally used as a proxy for risk. Though this pedagogic assumption makes for easy teaching, it is dead wrong: Volatility is *far* from synonymous with risk.** Popular formulas that equate the two terms lead students, investors and CEOs astray."[2]

> **"Volatility is our friend. Volatility has nothing to do with risk."**
> *- Mohnish Pabrai**

(continued on back)

It's a Matter of Time, Not Timing

Most experienced investors do not fear volatility, only unrecoverable loss. But most losses, as measured by a day, a week, a quarter or a year, are recoverable over time. Declines in principal value have historically been temporary. Of course, there are true risks. A company could go totally out of business. An innovation could transform an industry so profoundly to make a once "blue chip" company a relic. A geopolitical event could happen to negate all assumptions. But these occurrences are rare. For the vast majority of investors, maintaining a long-term perspective is the real key to attaining gains over their investing lifetime. Historically, since World War II, the longer you hold stocks, the narrower the range of returns.[3] In other words, even if volatility is a concern, it decreases the longer you hold stocks. It's the old adage: what matters is time in the market, not market timing.

"You can't overlook the volatility, but you don't let it push you around in the market."

*- Boone Pickens**

solutions designed to meet a broad array of investment goals. Whether you are looking for income or long-term capital appreciation, whether you choose to invest in equities, taxabl or tax-exempt fixed income or a hybrid fund of multiple asset classes, you can rely on the solid fundamentals of Value Line Funds.

Value Line Funds Include:
Equity Funds
Premier Growth Fund
Larger Companies Focused Fund
Mid Cap Focused Fund
Small Cap Opportunities Fund
Hybrid Funds
Asset Allocation Fund
Capital Appreciation Fund
Fixed Income Funds
Tax Exempt Fund
Core Bond Fund

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-2.48a

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to Table 2 on page 21 of Mr. Huffman's direct testimony on power generation volumes. Please:

a. Provide the same information in the table for calendar years 2020 to 2025 in Excel.

Answer: See attached file U-21973 AGDG-2.48a EUT PG 5-year CY.

Attachment: U-21973 AGDG-2.48a EUT PG 5-year CY

Michigan Public Service Commission	**Case No.:** U-21973
DTE Gas Company	**Requestor:** AG
U-21973 AGDG-2.48A EUT PG 5-year CY	**Related Question:** AGDG-2.48A
	Witness: J. L. Huffman
	Page: 1 of 1

TABLE 2 Power Generation Volumes

Calendar Year	Actual (Bcf)	Variance (Bcf) to 5-yr average	Cooling Degree Days	Variance to 15 yr Avg
2020	70.9	7.6	990	-5
2021	55.0	(8.3)	1,108	113
2022	56.7	(6.6)	1,040	45
2023	69.1	5.8	736	-259
2024	71.4	8.1	983	-12
2025	64.3	1.0	950	-45
Current 5-yr average	63.3			
15 Yr Avg CDD ('10~'24)			995	

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-2.49

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to lines 4-9 on page 21 of Mr. Huffman's direct testimony on the use of historical power generation volumes to forecast projected test year volumes. For each of the prior rate cases identified, please provide the volume included in the case's projected test year and the actual volume reported for the same periods in Excel.

Answer: The column labeled "Note" provides further insight on how large volume swings by one customer can greatly impact the power generation group volume which is also explained by Witness Huffman's direct testimony pg. 20, lines 1 through 11.

See attached file U-21973 AGDG-2.49 EUT PG Projected vs. Actual for details.

Attachment: U-21973 AGDG-2.49 EUT PG Projected vs. Actual

Michigan Public Service Commission
DTE Gas Company
U-21973 AGDG-2.49 EUT PG Projected vs. Actual

Case No.: U-21973
Requestor: AG
Related Question: AGDG-2.49
Witness: J. L. Huffman
Page: 1 of 1

Rate Case	Period	Projected Power Gen Volume	Actual Power Gen Volume	Variance	Note
U-18999	12 Months Ended September 2019	42.3	59.8	17.5	1 PG customer burned 15.1 Bcf above projected
U-20642	12 Months Ended September 2021	49.5	52.1	2.6	1 PG customer burned 3.5 Bcf above projected
U-20940	12 Months Ended December 2022	61.4	56.9	-4.5	1 PG customer burned 5.2 Bcf lower than projected
U-21291	12 Months Ended September 2024	60.7	73.6	12.9	2 PG customers burned 13.2 Bcf above projected

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.74b
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to Exhibit A-15, Schedule E7, page 2, on EUT volume changes. Please:

b. For line 3, provide the calculations in Excel showing how the EWR lost volumes were developed. Provide also the actual EWR volumes lost for each year 2023-2025 and provide evidence that those volumes were actually lost to EWR.

Answer: Attachment "U-21973 AGDG-2.74B EUT EWR Calculations" shows the calculations that are behind the EUT EWR impact reported in Exhibit A-15, Schedule E7, page 2, line 3. Through the process of responding to question PRA-1.5, it was determined there was a minor error in the calculated volume attributed to the EUT EWR impact. The (769) submitted should have been (746), meaning the EUT volume reduction attributed to EWR was unintentionally overstated by (23). The Company does not believe that the as-filed testimony or exhibits need to be updated.

Regarding actual EUT volumes lost per year that can be definitively attributed to customer efficiency measures, DTE does not have comprehensive data that isolates volume losses specifically caused by customer efficiency measures. Assumptions related to EWR impacts are litigated within the appropriate EWR proceedings and are based on Commission approved orders in those cases, in which the AG is a participating party.

Attachment: U-21973 AGDG-2.74b EUT EWR Calculations

Michigan Public Service Commission												**Case No.:**	U-21973
DTE Gas Company												**Requestor:**	AG
U-21973 AGDG-2.74B EUT EWR Calculations												**Related Question:**	AGDG-2.74B
												Witness:	J. L. Huffman
												Page:	1 of 1
EWR Volumes (Mcfs)													
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Annual**
2025	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	
EWR %	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	
Total Sales by rate class (Excl EWR)													
ST1	2,340,090	1,985,529	1,603,794	1,404,374	1,074,081	901,470	884,080	886,680	1,002,895	1,361,637	1,390,367	1,880,130	16,715,126
ST2	18,736	13,094	12,995	12,022	11,399	10,003	9,188	9,371	-	-	-	-	96,808
LT1	2,474,525	2,272,284	1,732,132	1,558,116	1,104,561	1,193,568	1,604,783	1,264,921	1,143,153	1,412,424	1,501,620	2,074,345	19,336,431
LT2	136,765	112,036	3,836	14,261	18,355	155,978	204,817	115,230	-	-	-	-	761,278
Prior Year Cumulative EWR Reductions													
LT													-
ST													-
EWR Effect on CY Sales													
LT	-	-	-	-	-	-	-	-	(11,432)	(14,124)	(15,016)	(20,743)	(61,315)
ST	-	-	-	-	-	-	-	-	(10,029)	(13,616)	(13,904)	(18,801)	(56,350)
Cumulative Effect of EWR Reductions for current year													
LT	-	-	-	-	-	-	-	-	(11,432)	(14,124)	(15,016)	(20,743)	(61,315)
ST	-	-	-	-	-	-	-	-	(10,029)	(13,616)	(13,904)	(18,801)	(56,350)
2026	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	
EWR %	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	
Total Sales by rate class (Excl EWR)													
ST1	2,233,992	1,975,761	1,779,661	1,465,292	1,120,699	959,866	928,001	923,830	1,028,088	1,386,645	1,414,029	1,899,616	17,115,481
ST2	-	-	-	-	-	-	-	-	-	-	-	-	-
LT1	2,422,295	2,136,485	1,923,857	1,563,525	1,167,088	1,281,784	1,392,297	1,264,852	1,152,853	1,422,224	1,511,420	2,084,145	19,322,825
LT2	-	-	-	-	-	-	-	-	-	-	-	-	-
Prior Year Cumulative EWR Reductions													
LT	-	-	-	-	-	-	-	-	(11,432)	(14,124)	(15,016)	(20,743)	(61,315)
ST	-	-	-	-	-	-	-	-	(10,029)	(13,616)	(13,904)	(18,801)	(56,350)
EWR Effect on CY Sales													
LT	(24,223)	(21,365)	(19,239)	(15,635)	(11,671)	(12,818)	(13,923)	(12,649)	(11,414)	(14,081)	(14,964)	(20,634)	(192,615)
ST	(22,340)	(19,758)	(17,797)	(14,653)	(11,207)	(9,599)	(9,280)	(9,238)	(10,181)	(13,730)	(14,001)	(18,808)	(170,591)
Cumulative Effect of EWR Reductions for current year													
LT	(24,223)	(21,365)	(19,239)	(15,635)	(11,671)	(12,818)	(13,923)	(12,649)	(22,846)	(28,205)	(29,980)	(41,377)	(253,931)
ST	(22,340)	(19,758)	(17,797)	(14,653)	(11,207)	(9,599)	(9,280)	(9,238)	(20,210)	(27,347)	(27,905)	(37,609)	(226,942)
2027	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**				
EWR %	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%	-1.00%				
Total Sales by rate class (Excl EWR)													
ST1	2,233,992	1,975,761	1,779,661	1,465,292	1,120,699	959,866	928,001	923,830	1,028,088				
ST2	-	-	-	-	-	-	-	-	-				
LT1	2,432,090	2,146,094	1,933,602	1,573,236	1,176,804	1,281,784	1,392,297	1,264,852	1,152,853				
LT2	-	-	-	-	-	-	-	-	-				
Prior Year Cumulative EWR Reductions													
LT	(24,223)	(21,365)	(19,239)	(15,635)	(11,671)	(12,818)	(13,923)	(12,649)	(22,846)				
ST	(22,340)	(19,758)	(17,797)	(14,653)	(11,207)	(9,599)	(9,280)	(9,238)	(20,210)				
EWR Effect on CY Sales													
LT	(24,079)	(21,247)	(19,144)	(15,576)	(11,651)	(12,690)	(13,784)	(12,522)	(11,300)				
ST	(22,117)	(19,560)	(17,619)	(14,506)	(11,095)	(9,503)	(9,187)	(9,146)	(10,079)				
Cumulative Effect of EWR Reductions for current year													
LT	(48,302)	(42,612)	(38,382)	(31,211)	(23,322)	(25,508)	(27,707)	(25,171)	(34,146)				
ST	(44,456)	(39,318)	(35,415)	(29,159)	(22,302)	(19,101)	(18,467)	(18,384)	(30,288)				

	Correct EUT EWR Effect 12 months ended 9/30/27	**Submitted EUT EWR Effect 12 months ended 9/30/27**	
	Volumes	**Volumes**	**Jnder/(Over)stated**
ST	(395,923)	(409,945)	**14,022**
LT	(349,753)	(359,468)	**9,715**
Total	(745,676)	(769,413)	**23,738**

Exhibit AG-37

CONFIDENTIAL

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-2.53a

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to page 35 of Mr. Huffman's direct testimony on Off-System Transportation revenue. Please:

a. Provide the list of contracts with volumes, rate, and revenue totaling $59.4 million in Excel.

Answer: Please see attachment.

Attachment: U-21973 AGDG-2.53a Off-System Transportation Revenue Volume & Rate

Michigan Public Service Commission						Case No.:	U-21973
DTE Energy Gas Company						Witness:	J. L. Huffman
		U-21973 AGDG-2.53a Off-System Transportation Revenue Volume & Rate					
Line No.	**Deal No.**	**Start Term**	**End Term**	**Service**	**Revenue**	**Volume**	**Rate**
1	1002132	5/2/2004	Open Ended	Blue Water	$ 36,000.00	-	0.000
2	90509	3/31/2013	1/31/2029	ANR	$ 6,798,000.00	32,353,626	0.041
3	90511	6/1/2011	6/1/2031	ANR	$ 10,571,400.00	53,992,301	0.130
4	04001-01	5/1/2016	1/31/2027	ANR	$ 48,362.52	693,470	0.500
5	Nexus 1	10/28/2018	10/27/2033	Nexus	$ 4,653,750.00	39,256,500	0.085
6	Nexus 2	10/28/2018	10/27/2033	Nexus	$ 2,326,875.00	19,628,250	0.085
7	Nexus 2 Cont	10/28/2018	10/27/2033	Nexus	$ 12,841,736.64	65,769,293	0.140
8	Nexus 3	10/28/2018	10/27/2033	Nexus	$ 12,328,294.80	176,791,124	0.050
9	04183-05	5/1/2017	4/30/2027	Off-System	$ 20,300.00	148,400	0.120
10	04216-08	6/1/2022	5/31/2027	Off-System	$ 2,586,833.28	18,528,750	0.085
11	04016-35	4/1/2022	3/31/2027	Off-System	$ 279,535.71	1,960,800	0.063
12	04057-17	11/1/2021	10/31/2026	Off-System	$ 6,564.93	5,332	0.265
13	04150-18	6/1/2023	5/31/2028	Off-System	$ 1,113,947.04	3,832,500	0.423
14	04078-08	12/14/2023	10/31/2033	Off-System	$ 740,824.96	1,532,370	0.100
15	04005-229	11/1/2023	10/31/2026	Off-System	$ 64,200.00	576,600	0.070
16	04078-10	11/1/2024	3/31/2029	Off-System	$ 166,100.00	158,550	0.220
17	04242-04	11/1/2024	10/31/2027	Off-System	$ 105,456.24	148,154	0.470
18	04048-24	4/1/2026	10/31/2030	Off-System	$ 304,950.03	1,829,700	0.075
19	04048-25	11/1/2026	3/31/2031	Off-System	$ 856,986.50	5,501,912	0.070
20	04061-249	11/1/2025	3/31/2029	Off-System	$ 340,312.50	453,000	0.150
21	04005-239	11/1/2025	3/31/2027	Off-System	$ 453,000.00	1,963,000	0.150
22	04053-19	12/1/2026	3/31/2036	Off-System	$ 689,000.00	3,445,000	0.100
23	04216-14	4/1/2025	3/31/2030	Off-System	$ 1,969,965.84	8,428,134	0.060
24	04057-20	11/1/2026	10/31/2031	Off-System	$ 75,484.31	284,600	0.277
					$ 59,377,880.30	437,281,365	$ 0.14
	AG Calculation			Off-System	$ 9,773,461.34	48,796,801	$ 0.20

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-2.53b

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to page 35 of Mr. Huffman's direct testimony on Off-System Transportation revenue. Please:

b. Provide the calculation in Excel for the unsigned transportation capacity with volume, assumed rate, and related revenue totaling $2.0 million.

Answer: Please see attachment U-21973 AGDG-2.53b Unsigned Transportation Revenue.

Attachment: U-21973 AGDG-2.53b Unsigned Transportation Revenue

Michigan Public Service Commission					Case No.:	U-21973
DTE Energy Gas Company					Witness:	J. L. Huffman
	Contract	Revenue	Rate	Volume		
	1	$ 650,160	$ 0.280	2,322,000		
	2	$ 91,714	$ 0.050	1,834,286		
	3	$ 14,500	$ 0.120	120,833		
	4	$ 1,293,417	$ 0.085	15,216,667		
		$ 2,049,791	$ 0.11	19,493,786		
AG Calculation		$ 3,898,757	$ 0.20	19,493,786		
Incremental Revenue		**$ 1,848,966**				
U-21973 AGDG-2.53b Unsigned Transportation Revenue						

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-2.53c

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to page 35 of Mr. Huffman's direct testimony on Off-System Transportation revenue. Please:

c. Provide the basis for the transportation rate assumed to arrive at the $2.0 million revenue. Explain how the Company arrived at this rate and provide supporting evidence.

Answer: The $2.0M of forecasted transportation revenue is based on expiring contracts that are expected to be renewed. The current rates were used to forecast the revenue of these renewals. Refer to U-21973 AGDG-2.53b Unsigned Transportation Revenue.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-2.53d

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to page 35 of Mr. Huffman's direct testimony on Off-System Transportation revenue. Please:

d. Provide the unsigned transportation capacity, assumed rate, and related forecasted revenue forecasted in Case U-21291 for the projected test year in that case compared to the actual revenue and the average rate realized for the same period in Excel.

Answer: Please see attachment U-21973 AGDG-2.53d Prior Rate Case Unsigned Transportation Revenue

Attachment: U-21973 AGDG-2.53d Prior Rate Case Unsigned Transportation Revenue

Michigan Public Service Commission — Case No.: U-21973
DTE Energy Gas Company — Witness: J. L. Huffman

Revenues

Contract	U-21291 Forecast	Actual	Variance
1	$ 629,736	$ 647,524	$ 17,788
2	$ 76,665	$ 166,100	$ 89,435
3	$ 820,329	$ 866,862	$ 46,533
	$ 1,526,730	$ 1,680,487	$ 153,756

Rates

Contract	U-21291 Forecast	Actual	Variance
1	$ 0.27	$ 0.28	$ 0.01
2	$ 0.10	$ 0.22	$ 0.12
3	$ 0.05	$ 0.05	$ -

Forecast Volume

Contract	U-21291 Forecast
1	2,331,000
2	755,000
3	16,406,585

U-21973 AGDG-2.53d Prior Rate Case Unsigned Transportation Revenue

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-2.77c_Supplemental

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to Exhibit A-13, Schedule 3.3, on Midstream Revenue. Please:

c. For the same four items, provide the projected test year revenue forecasted by the Company for the projected test year in each of the past three rate cases and the actual revenue achieved for those same periods.

Answer: Please see attachment.

Attachment: U-21973 AGDG-2.77c Off-System Revenues Compared to Prior Rate Cases

DTE Gas Response to DR AGDG-2.77c

Michigan Public Service Commission		Case No.: U-21973		**U-21973 AGDG-2.77c Off-System Revenues Compared to Prior Rate Cases**							
DTE Energy Gas Company		Witness: J. L. Huffman									
(a)		(b)	(c)	(d)	(b)	(c)	(d)	(b)	(c)	(d)	
		For the 12 Months Ended September 2025			**For Year Ended 2022**			**For the 12 Months Ended September 2021**			
Line No.	**Description**	**Actual Results Recognized**	**As Submitted in case U-21291**	**Submitted vs Actuals**	**Actual Results Ended 2022**	**As Submitted in case U-20940**	**Submitted vs Actuals**	**Actual Results Recognized**	**As Submitted in case U-20642**	**Submitted vs Actuals**	
Revenue ($000s)											
1	Contract Storage	$ 43,562	$ 34,079	$ 9,483	$ 28,675	$ 28,001	$ 674	$ 30,378	$ 29,467	$ 911	
2	Park & Loan	$ 6,144	4,390	$ 1,754	3,878	3,600	$ 278	4,007	5,842	$ (1,835)	
3	Total Midstream Storage Revenue	$ 49,706	$ 38,469	$ 11,238	$ 32,554	$ 31,601	$ 953	$ 34,385	$ 35,309	$ (924)	
4											
5											
6	Off-System Transportation	$ 62,332	$ 60,381	$ 1,951	$ 61,573	$ 60,362	$ 1,211	$ 61,544	$ 59,005	$ 2,539	
7	Exchange	21,069	12,793	$ 8,276	16,094	9,000	$ 7,094	16,645	10,056	$ 6,589	
8	Total Transportation Revenue	$ 83,401	$ 73,175	$ 10,227	$ 77,667	$ 69,362	$ 8,305	$ 78,189	$ 69,061	$ 9,128	
9											
10	Total Midstream Revenues	$ 133,108	$ 111,644	$ 21,464	$ 110,221	$ 100,963	$ 9,258	$ 112,574	$ 104,370	$ 8,204	

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.79a_Supplemental
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to the Item 10 schedule on the Home Protection Plan included in the Part III information provided with the Company's rate case filing. Please:

a. Expand this schedule to include the same actual information for each year 2019 to 2025 and provide it in Excel.

Answer: See attachments.

The following errors were discovered in the Part III – Supplemental Data, Subsection 10, Attachment 5 (11 & 12) or the U-20676 DTE Gas Company Code of Conduct Report – VAPS 2024 Annual Filing Correction:

1. Corporate Allocations (Code of Conduct Report only)
2. State and Federal Taxes (Part III – Supplemental Data only)
3. Operating Expenses – Other (Part III – Supplemental Data only)

With this response, the Company is filing a revised Part III – Supplemental Data, Subsection 10, Attachment 5 (11 & 12) and a revised U-20676 DTE Gas Company Code of Conduct Report – VAPS 2024 Annual Filing Correction. These errors have been corrected and are highlighted in red.

See attached file U-21973 AGDG-2.79a-b 01 2019-2025 VAPS Summary.

See attached file U-21973 AGDG-2.79a 02 Revised Part III – Supplemental Data, Subsection 10, Attachment 5 (11 & 12).

Attachment: U-21973 AGDG-2.79a-b 01 2019-2025 VAPS Summary

U-21973 AGDG-2.79a 02 Revised Part III – Supplemental Data, Subsection 10, Attachment 5 (11 & 12)

Co-Respondent(s): Legal

Home Protection Plus
Financial Detail
2019 - 2025

U-21973 AGDG-2.79ab 01 2019-2025 VAPS Summary

		2019	2020	2021	2022	2023	2024	2025
Operating Revenue								
	Total Operating Revenue	**$82,197,607**	**$86,577,858**	**$92,906,468**	**$99,256,889**	**$103,901,297**	**$108,545,733**	**$116,791,953**
	Avg Contracts	218,629	222,004	221,766	223,627	223,307	224,173	224,524
Operating Expenses								
	Labor and Benefits	$15,415,357	$15,405,847	$15,933,268	$15,812,773	$13,454,384	$14,370,719	$16,020,241
	Vendor Repairs	$19,764,704	$19,067,640	$30,326,354	$32,407,113	$31,864,020	$31,333,255	$33,041,532
	Advertising	$5,602,200	$3,011,446	$4,420,128	$5,230,653	$5,409,418	$6,480,403	$8,995,599
	Material	$3,151,240	$2,662,333	$4,245,435	$2,982,737	$4,234,881	$5,257,208	$6,548,322
	Other[4]	$12,490,205	$13,401,419	$9,409,065	$9,925,832	$9,137,270	**$10,711,945**	$11,039,238
	Total Direct Expenses	**$56,423,705**	**$53,548,685**	**$64,334,250**	**$66,359,109**	**$64,099,972**	**$68,153,530**	**$75,644,932**
Gross Margin		**$25,773,902**	**$33,029,173**	**$28,572,218**	**$32,897,780**	**$39,801,324**	**$40,392,203**	**$41,147,021**
Indirect Expenses								
A	Corporate Allocations[1]	**$ 5,726,613**	**$ 5,789,019**	**$ 6,116,998**	$6,714,492	$5,322,083	$5,811,529	$6,089,618
B	Federal Taxes[2]	**$ 4,200,574**	**$ 5,415,364**	**$ 4,675,498**	$5,498,491	$7,240,641	$7,261,942	$7,362,055
B	State Taxes[3]	**$ 1,200,164**	**$ 1,600,600**	**$ 1,460,537**	$1,717,624	$2,261,838	$2,268,492	$2,299,766
Total Indirect Expenses		**$11,127,351**	**$12,804,983**	**$12,253,033**	**$13,930,606**	**$14,824,562**	**$15,341,962**	**$15,751,438**
Total Expenses		**$67,551,057**	**$66,353,667**	**$76,587,283**	**$80,289,715**	**$78,924,534**	**$83,495,493**	**$91,396,370**
Profit		**$14,646,551**	**$20,224,191**	**$16,319,185**	**$18,967,174**	**$24,976,763**	**$25,050,240**	**$25,395,583**
Federal Tax		21%	20.3%	21%	21%	21%	21%	21%
State Tax		6.00%	6.16%	6.56%	6.56%	6.56%	6.56%	6.56%
Profit Margin %		17.82%	23.36%	17.57%	19.11%	24.04%	23.08%	21.74%

A - Includes corporate allocations from the Gas utility using the Massachusetts formula

B - The 2025 federal and state tax values are preliminary. Actuals in 2025 VAPS filing may differ.

1. Corporate Allocations: Revised the 2019, 2020, and 2021 corporate allocation values due to misalligned formula inputs (e.g. margin and ST labor). The revisions have been deemed immaterial.

2. Federal Taxes: Revised the 2019, 2020, and 2021 federal tax values due to a hardcoded value. The revisions have been deemed immaterial.

3. State Taxes: Revised the 2019, 2020, and 2021 state tax values due to a hardcoded value. The revisions have been deemed immaterial.

4. Operating Expenses - Other: Revised the 2024 Operating Expenses - Other value to include postage and write-off costs.

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.79b
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to the Item 10 schedule on the Home Protection Plan included in the Part III information provided with the Company's rate case filing. Please:

b. Provide the number of customers participating in the plan for each year 2019 to 2025 in Excel.

Answer: DTE Gas objects to this request on the grounds that it seeks confidential, proprietary, commercially sensitive, or trade secret information. Disclosure of such information could result in competitive harm to the Company and/or its customers. Subject to this objection, and without waiving this objection:

See attached file NDA U-21973 AGDG-2.79a-b 01 2019-2025 VAPS Summary for the number of customers participating in the plan (contracts) by year. In this attachment, the Company has supplemented Part III to include contract information for the Home Protection Plan.

Attachment: NDA U-21973 AGDG-2.79a-b 01 2019-2025 VAPS Summary

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.79c
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to the Item 10 schedule on the Home Protection Plan included in the Part III information provided with the Company's rate case filing. Please:

c. Refer to Footnote A on corporate cost allocations from the gas utility. Explain if the Company reduced the O&M expenses presented in the exhibits filed in this rate case for the $5,811,529 allocated to the HPP for 2024 and subsequent years. If the filed O&M exhibits are net of these costs allocated to HPP, identify the applicable exhibits and on which page and line of the exhibit the deductions are included.

Answer: The HPP schedule in Item 10 of the Part III information summarizes revenues and costs included in various exhibits in this rate case. They are not incremental to the amounts in the rate case exhibits; the Company is not requesting $5.8 million of additional expenses. HPP gross revenue is shown on Exhibit A-13, Schedule C3, line 11. The $5.8 million of corporate costs related to the HPP program are included within the total costs shown on O&M Exhibit A-13, Schedules C5.4 (Customer Service), C5.5 (Marketing) and C5.6 (Administrative and General).

Attachment: None

Other O&M Expense Adjustments

($000)

Line	Caption	Proposed Changes	O&M Level	Reference or Note
	(a)	(b)	(c)	(d)
1	**O&M Per Company Exh. A-13, Sched. C5**		**$ 543,793**	
	AG Proposed Changes			
2	Eliminate Proposed Blended Inflation	$ (4,480)		Ex. AG-50
3	Transmission Pipeline Integrity Expense	(4,687)		Testimony
4	Transmission ROW Maintenance	(4,000)		Testimony
5	Advanced Leak Detection Program	(9,000)		Testimony
6	Gas Leak Repairs	(4,000)		Testimony
7	Gas Leak and Work Management Training Expense	(1,500)		Testimony
8	Damage Prevention Expense	(2,678)		Testimony
9	Staking Leadership Expense	(664)		Testimony
10	Regulator Station Replacement Program Expense	(1,728)		Testimony
11	Employee Refresher Training Expense	(1,896)		Testimony
12	Public Awareness Program	(1,000)		Testimony
13	New Employee VEBA Plan	(880)		Ex. AG-51
14	Employee Saving Plan	(1,385)		Ex. AG-54
15	Active Health Care	(1,995)		Ex. AG-56
16	Incentive Compensation	(13,265)		Testimony
17	Rents-Shared Assets	(4,445)		Ex. AG-59
18	Uncollectible Accounts Expense	(1,043)		Testimony
19	Rate Case Expense	(209)		Testimony
20	Total Cost Changes	(58,855.0)	(58,855.0)	Sum Lines 2 to 19
21	**AG Proposed O&M (L1 + L20)**		**$ 484,938.0**	
22	***Change in O&M Expense (L21 less L1)***		***$ (58,855.0)***	

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.220b
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to Table 5 on page 22 of Mr. Kehoe's direct testimony on Pipeline Integrity Expenses. Please:

b. Provide the number of miles or work units supporting the expenses incurred each year 2022-2025 and forecasted for 2026 and 2027 in Excel. For each year, explain specifically what was done or is planned to be done.

Answer: DTE Gas objects for the reason that the request is unclear and unduly vague and incapable of answer in its present form since the Company is unclear regarding the meaning of "specifically what was done." Subject to this objection, and without waiving this objection, DTE Gas would answer as follows:

Please see attachment showing the specific work that was completed each year from 2022-2027. Every year in pipeline integrity O&M, the work is comprised of several ILI and DA assessments and their associated remediation as shown in the tables. In addition, there are other field and programmatic related work that is completed such as records remediation, TIMP program documentation updates, risk model updates and analysis, class location studies, HCA analysis, etc.

Attachment: U-21973 AGDG-6.220b 2022-2027 Pipeline Integrity Work Completed

2022	Assessment Type	Assessment	Remediation	Subtotal	# of O&M Digs
West Columbus 24"	ILI	$ 0.4	$ 0.1	$ 0.5	
West Columbus 20"	ILI	$ 0.2	$ -	$ 0.2	
Kalkaska Woolfolk	ILI	$ 0.3	$ -	$ 0.3	
Northeast Belt	ILI	$ 1.2	$ 0.4	$ 1.6	
Columbus 16"	ILI	$ 0.5	$ -	$ 0.5	
Great Lakes Petoskey	ILI	$ 0.6	$ 0.4	$ 1.0	
Milford K Line	ILI	$ 2.0	$ 2.3	$ 4.3	
First Energy	ILI	$ 0.4	$ -	$ 0.4	
Kingsley Gate Station	DA			$ 0.2	
Austin Detroit A Line Remediation	NA			$ 1.5	
2021 Carryover	NA			$ 0.2	
Sparta Muskegon Defect Removal	NA			$ 0.1	
TIMP Program Maintenance	NA			$ 1.2	
Record Defect Remediation (Traverse City West)	NA			$ 0.2	
Record Defect Remediation (Traverse City)	NA			$ 0.5	
Record Defect Remediation (West Bloomfield)	NA			$ 0.1	
Record Defect Remediation (Willow)	NA			$ 1.9	
Record Defect Remediation (Ravenna Gate)	NA			$ 0.5	
Record Defect Remediation (Southern Station)	NA			$ 0.4	
TIMP Routine	NA			$ 0.1	
DIMP Routine	NA			$ 0.6	
Total	**NA**			**$ 16.3**	

2023	Assessment Type	Assessment	Remediation	Subtotal	# of O&M Digs
Lincoln-Traverse City (10)	ILI	$ 1.6	$ 0.8	$ 2.4	7
Belle River St. Clair	ILI	$ 0.2	$ -	$ 0.2	0
Evergreen	ILI	$ 0.6	$ 0.1	$ 0.7	1
Southfield	ILI	$ 1.8	$ 0.7	$ 2.6	6
Sparta Muskegon Crack Remediation	NA		$ 0.3	$ 0.3	6
2022 Carryover	NA			$ 0.2	
TIMP Program Maintenance	NA			$ 1.1	
Record Defect Remediation (Southfield)	NA			$ 0.4	
DIMP Overburden	NA			$ 0.1	
TIMP Routine	NA			$ 0.2	
DIMP Routine	NA			$ 0.4	
Total				**$ 8.6**	**20**

2024	Assessment Type	Assessment	Remediation	Subtotal	# of O&M Digs
Muskegon - Ludington (10)/Scottville	ILI	$ 0.7	$ 1.1	$ 1.8	6
Muskegon - Ludington (12)	ILI	$ 0.5	$ 0.1	$ 0.7	1
South Suburban	ILI	$ 1.0	$ 0.1	$ 1.3	1
Alpena 12	ILI	$ 1.4	$ 0.8	$ 2.3	11
Fort Street	PT			$ 2.3	
Southern Station	DA			$ 0.5	5
Munising 4"	DA			$ 0.4	13
Casings DA	DA			$ 0.5	4
Traverse City Gate Station	DA			$ 0.2	0
Traverse City West Gate Station	DA			$ 0.2	2
Lincoln-Traverse City (10)	NA		$ 0.1	$ 0.2	3
TIMP Program Maintenance	NA			$ 0.7	
Crack Remediation (C, BR-Detroit, Ann Arbor)	NA			$ 2.8	15
Record Defect Remediation (Colwater Mt. Pleasant)	NA			$ 0.5	
TIMP Routine	NA			$ 0.8	
DIMP Routine	NA			$ 0.4	
Previous Carryover/Future ILI Prep	NA			$ 0.1	
Total				**$ 15.7**	**61**

2025	Assessment Type	Assessment	Remediation	Subtotal	# of O&M Digs
Austin - Detroit C	ILI	$ 4.6	$ 1.4	$ 6.1	10
East Outer Drive	ILI	$ 0.7	$ 0.1	$ 0.8	1
Van Born (36)	ILI	$ 1.2	$ 0.3	$ 1.5	1
Alpena 16 (2 Separate Segments)	ILI	$ 2.7	$ 2.1	$ 4.9	14
Rogers City	ILI	$ 0.9	$ 0.7	$ 1.6	5
Austin - Detroit A	ILI	$ 1.6	$ 6.8	$ 8.3	35
Ann Arbor (ILI and Crack Remediation)	ILI	$ 0.8	$ 2.0	$ 2.9	30
Loreed Tie Line/Loreed-Ludington	ILI	$ 0.7	$ -	$ 0.7	0
Northeast Gate	DA			$ 0.4	1
Willow Gate	DA			$ 0.4	2
Van Born 30" Remediation (2021 Assessment)	NA			$ 0.7	2
TIMP Program Maintenance	NA			$ 0.6	
Crack Remediation (Belle River-Detroit)	NA			$ 1.2	12
Record Defect Remediation (A Line)				$ 1.1	3
Record Defect Remediation (Belle River-Detroit)				$ 1.3	10
Record Defect Remediation (Big Rapids GS)				$ 0.4	
Record Defect Remediation (Northeast GS)				$ 0.1	0
Previous Carryover/Future ILI Prep				$ 0.2	
TIMP Routine	NA			$ 0.4	
DIMP Routine	NA			$ 0.5	
Total				**$ 34.1**	**126**

2026	Assessment Type	Total Assessment Cost	Total Remediation Cost	9 Months Sept 2026	3 Months Dec 2026
Austin Detroit B Line	ILI	$ 1.5	$ 9.2	$ 5.7	$ 5.0
Sparta Muskegon	ILI	$ 0.7	$ 0.4	$ 1.1	$ -
Sumpter/Sumpter Extension	ILI	$ 0.7	$ 0.3	$ 1.0	$ -
Powers - Gladstone (Escanaba Paper Tap to Gladstone)/Munisi	ILI	$ 0.8	$ 0.7	$ 1.5	$ -
Austin Detroit C (Remediation)	N/A	$ -	$ 8.0	$ 7.0	$ 1.0
Austin Detroit A (Remediation)	N/A	$ -	$ 4.6	$ 4.6	$ -
Van Born Remediation	N/A		$ 1.3	$ -	$ 1.3
Northwestern Gate Station/West Bloomfield Meter Station	DA	$ 0.3	$ -	$ 0.3	$ -
Sumpter Gate Station	DA	$ 0.4	$ 0.3	$ 0.7	$ -
TIMP Maintenance	N/A	$ 0.8	$ -	$ 0.6	$ 0.2
Total		**$**	**30.0**	**$ 22.5**	**$ 7.5**

2027	Assessment Type	Total Assessment Cost	Total Remediation Cost	9 Months Sept 2027	Number of Projected O&M Digs
Austin - Detroit A	ILI	$ 3.0	$ 4.0	$ 4.0	45
Austin - Detroit B	ILI	$ 3.5	$ 4.0	$ 5.0	65
Austin - Detroit C Remediation	N/A	$ -	$ 4.0	$ 2.0	40
Mackinaw (08) (Cheboygan to Vanderbilt)	ILI	$ 0.6	$ 0.8	$ 1.5	9
Milford-Belle River (E) 36"	ILI	$ 0.6	$ 0.8	$ 1.4	8
Belle River - Detroit	ILI	$ 0.5	$ 0.5	$ 1.0	5
Trufant	ILI	$ 1.5	$ 1.5	$ 2.0	15
Menominee Powers	ILI	$ 0.7	$ 0.8	$ 1.5	8
Kalkaska Woolfolk	ILI	$ 0.4	$ 0.1	$ 0.5	1
Columbus (12)	ILI	$ 0.4	$ 0.3	$ 0.7	3
Columbus (30)	ILI	$ 0.4	$ 0.4	$ 0.8	4
Gaylord/Mackinaw (08) (Vanderbilt to Weyerhauser)	ILI	$ 0.5	$ 0.5	$ 0.8	7
Great Lakes Mackinaw/Mackinaw (06)	ILI	$ 0.5	$ 0.5	$ 0.8	5
Frankfort 8"	ILI	$ 0.8	$ 0.5	$ 1.3	5
Powers - Gladstone (Powers Junction to Escanaba Paper Tap)	ILI	$ 0.8	$ 0.7	$ 1.0	7
Powers - Iron River 10"/8"	ILI	$ 1.5	$ 1.5	$ 2.6	15
Belle River - Detroit MLV 2A	DA	$ 0.3	$ -	$ 0.3	0
Alpena 16" Remediation	N/A	$ -	$ 4.0	$ 4.0	40
Ann Arbor Remediation	N/A	$ -	$ 0.3	$ 0.3	3
TIMP Maintenance	N/A	$ 0.8	$ -	$ -	0
Total		**$**	**42.0**	$ 31.5	**285**

U-21973 AGDG-6.220b 2022-2027 Pipeline Integrity Work Completed

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.220c
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to Table 5 on page 22 of Mr. Kehoe's direct testimony on Pipeline Integrity Expenses. Please:

c. Explain why for 2025 the number of inspections and assessments are about the same as 2024 but the expense doubles. Provide specifics to support your answer.

Answer: Please refer to my direct testimony, beginning on page 24.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.220d
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to Table 5 on page 22 of Mr. Kehoe's direct testimony on Pipeline Integrity Expenses. Please:

d. Explain why for 2026, the number of inspections and assessments are cut nearly half from 2025, but the expense remains the same. Provide specifics to support your answer.

Answer: Please refer to my direct testimony, beginning on page 24.

Attachment: None

MPSC Case No: U-21973
Requester: Staff
Question No.: STDG-2.13_Supplemental
Respondent: S. Kehoe
Page: 1 of 1

Question: Referring to Page 22, Table 5, of Company witness Scotty N. Kehoe's direct testimony; are the 2025 values provided in Table 5. Historical and Forecasted Pipeline Integrity Expenses, including In-Line Inspections and Direct Assessments full-year 2025 actuals? If not, please provide an update to Table 5 to include full-year 2025 actual values. Additionally, please update Table 5 to include full-year actual values for the calendar years 2023, 2022, 2021, 2020, and 2019.

Answer:

Year	Number of In Line Inspections and Direct Assessments	O&M Expenses
2019	12	$17.5 M
2020	11	$10.6 M
2021	12	$18.6 M
2022	9	$16.3 M
2023	4	$8.6 M
2024	10	$15.7 M
2025	10	$34.1 M
2026	6	$30.0 M
2027	16	$42.0 M

Attachment: None.

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.228a
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to lines 16-25 on page 48 and Table 18 on page 49 of Mr. Kehoe's direct testimony on Transmission ROW maintenance. Please:

a. When did the Company begin the continuous five-year cycle?

Answer: 2025.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.228c
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to lines 16-25 on page 48 and Table 18 on page 49 of Mr. Kehoe's direct testimony on Transmission ROW maintenance. Please:

c. Provide the total number of miles of transmission ROW the Company wants to maintain on a five-year cycle.

Answer: 1,380 miles of ROW. Note that some pipelines share a ROW.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.228d
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to lines 16-25 on page 48 and Table 18 on page 49 of Mr. Kehoe's direct testimony on Transmission ROW maintenance. Please:

d. Expand Table 18 to include the same information for each year 2020 to 2025 and forecasted for 2027 along with the dollars for each of the three categories in Excel.

Answer: The Company does not track expenses separately for the three types of ROW maintenance. Please see attachment.

Attachment: U-21973 AGDG-6.228d Transmission ROW Historical Data

Year	Mechanical Brushing	Spraying	Canopy Management	O&M Expense ($M)
2020	11			0.2
2021	62			0.3
2022	124			1
2023	0			0
2024	21			0.7
2025	200			1.5
2026 Forecast	300	200	200	6.0
2027 Forecast	300	200	200	6.0
U-21973 AGDG-6.228d Transmission ROW Historical Data				

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.239a
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to page 80 of Mr. Kehoe's direct testimony on Training for Gas Leak Survey. Please:

a. Provide the expense leak survey training for each year 2022-2025 and forecasted for 2026 and 2027 in Excel.

Answer: Please see attached. The known and measurable change is for both the IFS Workforce Management System and the KloudGin Leak Survey Technology.

Attachment: U-21973 AGDG-6.239a IFS and KloudGin Historical Data

Year	O&M Expense ($M)			
2022	0			
2023	0			
2024	0			
2025	1.0			
2026 Forecast	2.1			
2027 Forecast	3.3			
U-21973 AGDG-6.239a IFS and KloudGin Historical Data				

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.239c
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to page 80 of Mr. Kehoe's direct testimony on Training for Gas Leak Survey. Please:

c. Identify how many in-house trainers will be used for $1.4 million and the number of contracted trainers for $1.8 million.

Answer: The $1.4 and $1.8 million known and measurable change is for both the IFS Work Management System and KloudGin Leak Survey Management Technology live. Seven internal resources will be utilized for training activities.. The $1.8 million in contract service expenses is to bring the IFS Work Management System live.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.242i
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to pages 88-91 and Table 37 of Mr. Kehoe's direct testimony on the Advanced Leak Detection program and expense. Please:

i. Confirm that the final NPRM has not yet been issued and provide the date when it is expected and the source of that information. If not confirming, explain.

Answer: There are currently no updated approximate dates or details related to an upcoming LDAR NPRM from PHMSA.

Regardless of the outcome of the NPRM, the Company believes that Advanced Leak Detection technology is beneficial to customers and should be incorporated into the existing system. Advanced Leak Detection promotes a proactive leak detection process and is more prudent than reactively responding. Adopting this technology will enhance the safety and reliability of the system.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.244a
Respondent: S. Kehoe
Page: 1 of 2

Question: Refer to Table 39 on page 96 of Mr. Kehoe's direct testimony on leak repairs and costs. Please:

a. Expand the table to include the same information for each year 2018-2025 and forecasted for 2027 and provide it in Excel. Provide also any O&M expense for leak repairs for each year in the expanded table.

Answer: Please find the expanded table for each year 2018-2025 below. DTE Gas will forecast incoming leaks and leak repairs for 2027 later in 2026 based on Miles of Main and Services renewed as part of the 2026 Gas Renewal Program, leak volume from annual Leak Survey, and updated projections of 2026 year-end Leak Backlog if applicable.

	Leaks					Exp ($MM)	Expense ($MM)
	Jan. 1	Incoming Leaks	Leaks Repaired	Year End Balance		Capital	Expense
2018 Actuals	836	7,818	8,068	586		$8.0	$13.6
2019 Actuals	586	7,082	7,122	546		$7.9	$14.6
2020 Actuals	546	7,279	5,759	2,066		$4.0	$7.9
2021 Actuals	2,066	5,924	5,759	992		$4.2	$15.6
2022 Actuals	992	5,303	5,439	856		$3.7	$13.1
2023 Actuals	856	6,383	5,488	1,751		$3.9	$9.6
2024 Actuals	1,751	5,336	5,825	1,262		$4.5	$11.1
2025 Actuals	1,262	4,803	4,791	1,274		$4.6	$8.5
2026 Forecasted	1,274	5,751	4,385	2,640		$4.1	$7.1

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.233b
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to Table 28 and lines 15-21 on page 73 of Mr. Kehoe's direct testimony on MISS DIG for Distribution. Please:

b. Provide the number of tickets received by the Company from MISS DIG for Distribution for each year 2018-2025 and forecasted for 2026 and 2027 in Excel.

Answer: Please see attachment.

Attachment: U-21973 AGDG-6.233b Historical Distribution MISS DIG Ticket Volume

Year	MISS DIG Distribution Ticket Volume		
2018	310,807		
2019	304,308		
2020	256,740		
2021	321,247		
2022	348,248		
2023	405,085		
2024	427,543		
2025	425,356		
2026 Forecast	437,721		
2027 Forecast	459,607		
U-21973 AGDG-6.233b Historical Distribution MISS DIG Ticket Volume			

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.240a
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to page 85 and Table 35 of Mr. Kehoe's direct testimony on Damage Prevention expense. Please:

a. Provide the total damage prevention expense for each year 2022-2025 and forecasted for 2026 and 2027 in Excel.

Answer: Please see attachment.

Attachment: U-21973 AGDG-6.240a Damage Prevention Actuals

Year	O&M Expense ($M)
2022	1.7
2023	1.6
2024	1.6
2025	1.3
2026 Forecast	1.6
2027 Forecast	2.6

U-21973 AGDG-6.240a Damage Prevention Actuals

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.240b
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to page 85 and Table 35 of Mr. Kehoe's direct testimony on Damage Prevention expense. Please:

b. Show in Excel how the $1.8 million for labor and $0.6 million for Other were determined in Excel.

Answer: Please see attachment.

Attachment: U-21973 AGDG-6.240b Damage Prevention K&M

DTE Gas Response to DR AGDG-6.240b

Category	Number of FTEs	ST Labor ($ M)	Material ($M)	Contract Services ($M)	Other Indirects ($ M)
Damage Prevention Liaisons	7	1.21			0.34
Analyst	1	0.15			0.06
Supervisors	2	0.44			0.18
Equipment/Material			0.09		
New Technology Forecasting				0.13	
Total	10	1.8	0.09	0.13	0.58
U-21973 AGDG-6.240b Damage Prevention K&M					

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.241b
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to pages 86-87 and Table 36 of Mr. Kehoe's direct testimony on the Staking Leadership expense. Please:

b. Explain what insourcing of Southeast staking means and why it was insourced. Provide any annual cost savings from the insourcing.

Answer: Staking was previously supported by contract and internal labor in Southeast Michigan territory. Staking was fully insourced in 2024 to be supported by internal labor resources only. Staking was insourced to address rising ticket volume, improve on-time performance, and improve the quality of staking. The decrease in contract expenses has been offset by the additional internal labor needed to fully insource.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.241c
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to pages 86-87 and Table 36 of Mr. Kehoe's direct testimony on the Staking Leadership expense. Please:

c. Explain what problem the insourcing solves.

Answer: Please see response AGDG-2.41b.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.241d
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to pages 86-87 and Table 36 of Mr. Kehoe's direct testimony on the Staking Leadership expense. Please:

d. Provide the number of difficult locate tickets received or addressed each year 2022-2025 and forecasted for 2026 and 2027.

Answer: The Company does not track difficult locate tickets separately from overall MISS DIG Tickets. Please refer to response AGDG-6.233b for MISS DIG Distribution ticket volume.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.241e
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to pages 86-87 and Table 36 of Mr. Kehoe's direct testimony on the Staking Leadership expense. Please:

e. Explain why four more field technicians are needed for the projected test year and provide the number of technicians at the end of each year 2022-2025 and forecasted for 2026 and 2027.

Answer: The Staking Leadership Program pilot began in Southeast Michigan. The pilot will be expanded to the Greater Michigan territory with the addition of four field technicians.

Year	Staking Leader Field Technicians
2022	0
2023	0
2024	0
2025[1]	6
2026	6
2027	10

1. As detailed on page 87 of my testimony, the Staking Leadership pilot began in 2025.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.241f
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to pages 86-87 and Table 36 of Mr. Kehoe's direct testimony on the Staking Leadership expense. Please:

f. Explain in which month the leadership program began in 2025.

Answer: May 2025.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.229a
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to Table 25 on page 68 and lines 14-24 on page 69 of Mr. Kehoe's direct testimony on the enhanced RSRP. Please:

a. Provide the total expense for this program for each year 2022-2025 and forecasted for 2026 and 2027 in Excel, along with the number of work units.

Answer: Please see attachment.

Attachment: U-21973 AGDG-6.229a RSRP Historical Data

Year	O&M Expense ($M)	Service and Regulator Inspections	Soft Good Replacements
2022	0	0	0
2023	0	0	0
2024	0.5	1,268	23
2025	1.6	1,065	241
2026 Forecast	3.6	1,000	282
2027 Forecast	3.6	1,000	282
U-21973 AGDG-6.229a RSRP Historical Data			

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-6.237c
Respondent: S. Kehoe
Page: 1 of 1

Question: Refer to Table 31 and lines 15-19 on page 78 of Mr. Kehoe's direct testimony on Gas Refresher Training. Please:

c. Show how the $1.9 million was determined in Excel and provide the number of employees that will get the training.

Answer: Please see attachment.

Attachment: U-21973 AGDG-6.237c Gas Refresher Training Known and Measurable

Number of Trainings	15	
Average Students per Training	145	
Average Training Duration (hours)	12.5	
Total Annual Student Training time (hours)	27,188	
Total Annual Student Training Cost	$1,471,626	
Total Annual Instructor Cost	$424,765	
Total Gas Refresher Training Known and Measurable	$1,896,391	
U-21973 AGDG-6.237c Gas Refresher Training Known and Measurable		

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.66a
Respondent: J. L. Huffman
Page: 1 of 2

Question: Refer to lines 16-23 on page 82 of Mr. Huffman's direct testimony on the current Public Awareness Program. Please:

a. Provide all the components of the program, what they entail, and the related expense for each year 2023 to 2025, and forecasted for 2026, 2027, and the projected test year, excluding the newly proposed $2 million in this rate case.

Answer: The current Public Awareness Program spends approximately $130,000 to the marketing of safety messages. The Company is requesting an additional $2 million specifically for this effort. In addition, a portion of Damage Prevention work is a component of the current Public Awareness Program. The full efforts are described in Witness Kehoe's testimony (page 65 lines 9-24; page 67 lines 12, 13, 21; page 71 line 22 through page 75 line 9; page 84 line 19 through page 86 line 23).

1. **Customer Safety Marketing Campaign**: This is a coordinated, multichannel campaign designed to communicate natural gas safety information to our customers. In a typical year, the Company spends approximately $130,000. When averaging 2023 and 2024, spending is slightly below this level. The 2024 historical period includes $193,817 in expenditure. In 2025, following an increase in incidents involving natural gas equipment that resulted in explosions, fires, injuries and fatalities, the Company proactively spent an additional $104,523 in customer gas safety communications.

2. **Damage Prevention Public Awareness**: The Damage Prevention program involves partnering with MISS DIG 811, excavators, municipalities, other utilities and locating teams to prevent excavation damage to DTE Gas Company assets. A portion of their work communicating to customers and educating excavators, municipalities and other utilities are included in our Public Awareness campaign.

Co-Respondent(s): S. Kehoe

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.66a
Respondent: J. L. Huffman
Page: 2 of 2

	2023	2024	2025	2026	2027	Projected Test Year
Customer Safety Marketing Campaign	$46,822	$193,817	$298,340	$193,817	$193,817	$193,817
Damage Prevention Public Awareness	$121,854	$127,431	$161,047	$177,146	$161,646	$161,646

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.66b
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to lines 16-23 on page 82 of Mr. Huffman's direct testimony on the current Public Awareness Program. Please:

b. Identify in which communication channels the money was spent and how much for each channel for each year 2023-2025.

Answer: A breakout of the Public Awareness Program communication channels is listed below.

	2023	2024	2025
Customer Safety Marketing Campaign			
General Materials	$787	$19,548	$20,851
Digital/Print Advertising	$6,879	$33,990	$156,550
Emails	$4,677	$19,420	$7,323
Customer Events (CO Giveaways)	$18,287	$36,342	$13,867
Paid Social	$5,427	$84,517	$43,000
Direct Mail	$10,765	$ 0	$44,937
Content Creation	$ 0	$ 0	$11,812
Total	**$46,822**	**$193,817**	**$298,340**
Damage Prevention Public Awareness (see Witness Kehoe's testimony)			
Paradigm	$103,834	$109,731	$122,647
Bill Insert	$18,020	$17,700	$35,400

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.66c
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to lines 16-23 on page 82 of Mr. Huffman's direct testimony on the current Public Awareness Program. Please:

c. Confirm that advertising, mailings, contractor communications, and other public awareness activities and spending related to MISS DIG and avoidance of damage to utility facilities is part of the current Public Awareness Program. If not, provide the activities and communications completed currently for digging damage prevention and the related costs incurred each year 2020-2025.

Answer: Yes. Advertising, mailings, contractor communications, and other public awareness activities related to educating on MISS DIG and the prevention of damage to utility facilities are components of the Company's current Public Awareness Program.

Details on the Company's overall Damage Prevention Efforts and execution of MISS DIG work can be found in Witness Kehoe's testimony (page 65 lines 9-24; page 67 lines 12, 13, 21; page 71 line 22 through page 75 line 9; page 84 line 19 through page 86 line 23.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.70
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to page 86 of Mr. Huffman's direct testimony on enhanced public education and awareness for leak recognition and response. Please identify on which items the additional $2 million will be spent and the amount related to each item.

Answer: Refer to Q/A 192 through Q/A 195 of my direct testimony for the description of the proposed Public Awareness Program, and associated risks if the requested funding is not approved.

Item	Amount
Gas-only Schools Program	$250,000
Direct Mail (1 per year)	$220,000
Mass/Paid Media (TV, Radio, Digital)	$1,415,000
Activation Collateral including Combo (CO & dangerous gas) Detectors	$30,000
ST Labor	$85,000
	$2,000,000

The intent of this effort is to increase awareness of Gas safety information. Accordingly, the plan is heavily weighted towards mass media as it enables us to reach audiences at scale and with sufficient frequency to impact message recall – helping customers understand the steps how to detect and respond to potential gas leaks to avoid recurrence of 2025 incidents. This plan also addresses underserved groups including the creation of a school program to help build foundational gas safety awareness among students.

All efforts will have key performance indicators that will be tracked, and the team will continue our existing efforts to benchmark and evaluate message impact to drive continuous improvements to our approach.

Attachment: None

O&M Reduction - Limit
Inflation Increases to the CPI (AG Position)

Line	Department (a)	Thousands of Dollars: Hist. 2024 O & M* (b)	Less Non Inflat. Items** (c)	Inflationary Items (d)	Inflation *** (e)
1	Natural Gas Storage	$ 10,747	$ -	$ 10,747	
2	Transmission	55,934	(1,834)	54,100	
3	Distribution	116,153	-	116,153	
4	Customer Service	53,675	(7,137)	46,538	
5	Marketing	51,129	-	51,129	
6	Admin. & General	114,841	(62,362)	52,479	
7	Pension & Benefits	30,597	(30,597)	-	
8	Total for 2024	$ 433,076	$ (101,930)	$ 331,146	
9	2025 Inflation (2.7% of Line 8)			8,941	$ 8,941
10	Inflation Base - End of 2025 (L 8 and L 9)			$ 340,087	
11	2026 Inflation (2.4% of Line 10)			8,162	8,162
12	Inflation Base - End of 2026 (L 10 + L 11)			$ 348,249	
13	2027 Inflation (2.3% x 75% of Line 12)			5,866	5,866
14	Total			**$ 345,953**	
15	**Cumulative 2024 and 2025 Inflation at 100% of CPI (L9 + L11 + L13)**				**$ 22,970**
16	Inflation per Ex. A-13, Sch. C5 columns (g), (h) and (i)				27,450
17	***O&M Inflation Elimination (L15 less L16)***				***$ (4,480)***

* Per Exhibit A-13, Schedule C5, column (f)

** Excludes TCARP Fees, Customer 360 Expense, Merchant Fees, Demand Response Expense, Incentive Deferral, Injuries & Damages as well as MGP Amortization and Shared Asset Changes, which do not change with inflation.

*** AG Calculated inflation based on economic projection in Exhibit AG-2 (AGDG 1.4 a) of 2.7%, 2.4% and 2.3% for 2025, 2026 and 2027.

New Hire VEBA
(Thousands of Dollars)

Line	*Projected Cost Information*	Actual* 2025	Projected 2026	Projected 2027	Test Year
	(a)	(b)	(c)	(d)	(e)
1	Actual 2025 Escalated 6.0% and 5.7% in 2026 & 2027 per Line 3	$ 2,097	$ 2,223	$ 2,350	**$ 2,318**
2	New Hire VEBA Participants (Increased by 175 per year) **	2,910	3,085	3,260	
3	% Increase - Participants		6.0%	5.7%	
4	Company Projection ***				3,198
5	**Reduction in New Hire VEBA Expense**				**$ (880)**

* Exhibit AG-52 (AGDG 7.319 a).

** Id. includes AGDG 7.319 b, the Company has increased New Hire Participation by approximately 175 employees per year (2018 to 2025) as follows. A total addition of 175 participants per year is used in the AG's calculation of higher costs in the projected test year. The Test Year Expense reflects 25%/75% for 2026 and 2027.

	New Hire VEBA Participants 2018	New Hire VEBA Participants 2025	Change Over Seven Years Total	Change Over Seven Years Avg. p/Year
Non Represented				
Gas	279	470		
LLC	779	1,367		
Local 223				
Gas	240	473		
LLC	389	600		
Total Participants	**1,687**	**2,910**	**1,223**	**175**

*** Per Exhibit A-13, Schedule C5.9, page 1, line 4

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-7.319a
Respondent: M. S. Cooper
Page: 1 of 1

Question: Refer to pages 11-13 of Mr. Cooper's direct testimony on the VEBA expense. Please:

a. Provide the actual VEBA expense for 2022-2025 and the calculation of the forecasted expense for 2026 and the projected test year In Excel with all components clearly identified.

Answer: Please see the attachment entitled "U-21973 AGDG-7.319a 2022-2025 VEBA Expense" for VEBA costs and expense for the years 2022 through 2025. and U-21973 AGDG-7.319a VEBA Projections" for the support for the projections. Please note that the support for projected test period is about $8,000 lower than the as-filed position due to minor rounding issue in the 2027 projection.

Attachment: U-21973 AGDG-7.319a 2022-2025 VEBA Expense
U-21973 AGDG-7.319a VEBA Projections

Michigan Public Service Commission														**Case No.**	**U-21973**
DTE Gas Company														**Requestor**	**AG**
New Hire VEBA Projections														**Question**	**AGDE-7.319a**
														Respondent	**M. S. Cooper**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Non Represented						**Local 223**							
Line		**Members Prior**		**Five-Year Average**	**Annualized Costs of**	**Prorated**		**Members Prior**		**Five-Year Average**	**Annualized Costs of**	**Prorated**			
No.		**Year End**	**Costs**	**Net Adds**	**Net Adds**	**Costs**	**Total Costs**	**Year End**	**Costs**	**Net Adds**	**Net Adds**	**Costs**	**Total Costs**	**Total Costs**	**O&M**
1	Annual Funding		4,000		4,000				2,163		2,163				
2															
3	**2025**														62.1%
4	Gas	483	1,932,000	44	174,400	87,200	2,019,200	452	977,533	18	38,496	19,248	996,781	3,015,981	
5															
6	LLC	1,408	5,632,000	110	441,600	220,800	5,852,800	663	1,433,860	55	118,083	59,041	1,492,901	7,345,701	
7															
8	LLC %	24.3%	24.3%			24.3%	24.3%	24.3%	24.3%			24.3%	24.3%	24.3%	
9															
10	LLC Billed to Gas	343	1,370,800			53,742	1,424,542	161	348,994			14,370	363,364	1,787,906	
11															
12	Total Gas	826	3,302,800			140,942	3,443,742	613	1,326,527			33,618	1,360,146	4,803,887	
13															
14	5 year average forfeitures						(278,843)						-	(278,843)	
15															
16	Total 2025						3,164,898						1,360,146	4,525,044	2,810,796
17															
18	**2026**														
19	Gas	527	2,106,400	44	174,400	87,200	2,193,600	470	1,016,029	18	38,496	19,248	1,035,277	3,228,877	
20															
21	LLC	1,518	6,073,600	110	441,600	220,800	6,294,400	718	1,551,942	55	118,083	59,041	1,610,983	7,905,383	
22															
23	LLC %	24.3%	24.3%			24.3%	24.3%	24.3%	24.3%			24.3%	24.3%	24.3%	
24															
25	LLC Billed to Gas	370	1,478,283			53,742	1,532,025	175	377,735			14,370	392,105	1,924,130	
26															
27	Total Gas	896	3,584,683			140,942	3,725,625	644	1,393,764			33,618	1,427,382	5,153,007	
28															
29	5 year average forfeitures						(278,843)							(278,843)	
30															
31	Total 2026						3,446,781						1,427,382	4,874,164	3,027,656
32															
33	**2027**														
34	Gas	570	2,280,800	44	174,400	87,200	2,368,000	488	1,054,525	18	38,496	19,248	1,073,773	3,441,773	
35															
36	LLC	1,629	6,515,200	110	441,600	220,800	6,736,000	772	1,670,025	55	118,083	59,041	1,729,066	8,465,066	
37															
38	LLC %	24.3%	24.3%			24.3%	24.3%	24.3%	24.3%			24.3%	24.3%	24.3%	
39															
40	LLC Billed to Gas	396	1,585,766			53,742	1,639,508	188	406,475			14,370	420,846	2,060,354	
41															
42	Total Gas	967	3,866,566			140,942	4,007,508	676	1,461,000			33,618	1,494,619	5,502,127	
43															
44	5 year average forfeitures						(278,843)							(278,843)	
45															
46	Total 2027						3,728,665						1,494,619	5,223,283	3,244,517
47															
48													9/30/2027		3,190,302

Michigan Public Service Commission
DTE Gas Company
New Hire VEBA 2022 - 2025
Costs and Expense
($000's)

Line No.	Year	VEBA Costs	VEBA Expense
	(a)	(b)	(c)
1	2022	3,823	2,437
2	2023	3,368	2,062
3	2024	3,579	2,223
4	2025	3,338	2,097

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-7.319b
Respondent: M. S. Cooper
Page: 1 of 1

Question: Refer to pages 11-13 of Mr. Cooper's direct testimony on the VEBA expense. Please:

b. Provide the number of participants for each year 2018 to 2025 and forecasted for 2026, 2027, and the projected test year.

Answer: Please see attachment entitled "U-21973 AGDG-7.319b VEBA Participants".

Attachment: U-21973 AGDG-7.319b VEBA Participants

Michigan Public Service Commission
DTE Gas Company
New Hire VEBA Participants

Case No.	U-21973
Requestor	AG
Question	AGDE-7.319b
Respondent	M. S. Cooper

Line No.	Year	Non Represented		Local 223	
		Gas	LLC	Gas	LLC
	(a)	(b)	(c)	(d)	(e)
1	2018	279	779	240	389
2	2019	325	931	363	390
3	2020	398	992	418	445
4	2021	442	1,065	406	442
5	2022	479	1,258	408	519
6	2023	497	1,331	446	731
7	2024	483	1,408	452	663
8	2025	470	1,367	473	600
9					
10	2026 (Forecast)	570	1,629	488	772
11	2027 (Forecast)	614	1,739	505	827
12	Proj. Test Year	603	1,712	501	813

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-7.319c
Respondent: M. S. Cooper
Page: 1 of 1

Question: Refer to pages 11-13 of Mr. Cooper's direct testimony on the VEBA expense. Please:

c. Provide the actual true-up amounts for each year 2018 to 2025 and the Company's calculation of true-up adjustments for 2026 and the projected test year in Excel.

Answer: Please see attachment entitled "U-21973 AGDG-7.319c VEBA True-up 2018-2025". Because future true-ups are based on actual forfeitures and other differences between initial accruals and actual funding requirements, the Company doesn't project true-ups.

Attachment: U-21973 AGDG-7.319c VEBA True-up 2018-2025

Michigan Public Service Commission
DTE Gas Company
VEBA True-ups
Case U-21973
AGDE-7.319c

Line No.	(a) Year	(b) Amount 1/
1	2018	(246,784)
2	2019	(125,421)
3	2020	(206,309)
4	2021	104,278
5	2022	(457,398)
6	2023	(857,681)
7	2024	(688,214)
8	2025	(1,015,709)
9		
10	1/ Total Gas cost before reduction for portion capitalized.	

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.25a
Respondent: M. A. Fix
Page: 1 of 1

Question: Refer to Exhibit A-13, Schedule C5.9, page 2, regarding the $2.7 million increase in expense for the savings plan. Please:

a. Provide the calculation in Excel with formulas intact and all supporting data showing how the projected test year amount was developed. Explain the reasons for the 26% increase in expense from the 2024 historical year.

Answer: The increase in the Employee Savings Plan (ESP) expense between 2024 and the 12 months ended September 30, 2027, of $2.7 million over almost three years (or about 8.5% per year) are twofold: (1) increase in new employees and (2) increase in average employee pay. Because the defined benefit pension plan was closed to all new employees after 2013, most new employees receive an automatic ESP contribution in lieu of pension of 4% of their eligible pay. Virtually all employees are also eligible to participate in the Company matching up to 6% of their eligible pay. Accordingly, the projection of future ESP contributions is differentiated between "In Lieu of Pension" and the Company match, which is entitled "401(k)" in the attachment. Almost two thirds of the increase in ESP costs for the projected test year relate to new employees.

Please see attachment entitled "U-21973 AGDG-2.25a Savings Plan Projected Test Year"

Attachment: U-21973 AGDG-2.25a Savings Plan Projected Test Year

DTE Gas Company
AGDG-2.5a Savings Plan Projected Test Year Detail

Case No. U-21973
Requestor AG
Question AGDE-2.5a
Respondent M. Fix

			401(k)					In Lieu of Pension					Total		
			LLC			Total		LLC			Total				
Line No		Gas	Total LLC	Percent	LLC to Gas	Gas	Gas	Total LLC	Percent	LLC to Gas	Gas	Gas	LLC	LLC to Gas	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	2024 Wages	153,244,472	293,140,906				89,434,665	162,612,509							
2	2024 Contribution	8,506,303	15,768,059	24.3%	3,825,931	12,332,234	4,102,883	6,476,959	24.3%	1,571,557	5,674,440	12,609,186	22,245,018	5,397,488	18,006,674
3	Avg Pay	87,719	96,778				51,193	84,518							
4	New Employees	36	119				103	404							
5	New Employees Pay	3,157,871	11,516,596				5,272,908	34,145,246							
6	2025 Wage Base	156,402,343	304,657,502				94,707,574	196,757,755							
7	Wage Inc %	3.0%	3.0%				3.0%	3.0%							
8	Increase in Wages	4,692,070	9,139,725				2,683,040	4,878,375							
9	2025 Wages	161,094,414	313,797,227				97,390,614	201,636,130							
10	Contribution %	5.6%	5.4%				4.6%	4.0%							
11	2025 Contribution	8,942,038	16,879,163	24.3%	4,095,527	13,037,565	4,467,868	8,031,294	24.3%	1,948,698	6,416,566	13,409,906	24,910,457	6,044,225	19,454,131
12	% Increase	5.1%	7.0%			5.7%	8.9%	24.0%			13.1%				8.0%
13	Avg Pay	90,350	99,681				52,729	87,053							
14	New Employees	96	30				251	305							
15	New Employees Pay	8,673,620	2,990,444				13,234,999	26,551,310							
16	2026 Wage Base	169,768,033	316,787,670				110,625,613	228,187,440							
17	Wage Inc %	3.0%	3.0%				3.0%	3.0%							
18	Increase in Wages	5,093,041	9,503,630				3,318,768	6,845,623							
19	2026 Wages	174,861,074	326,291,300				113,944,381	235,033,063							
20	Contribution %	5.6%	5.4%				4.6%	4.0%							
21	2026 Contribution	9,706,199	17,551,220	24.3%	4,258,594	13,964,792	5,227,285	9,361,515	24.3%	2,271,460	7,498,745	14,933,484	26,912,735	6,530,054	21,463,537
22	% Increase	8.5%	4.0%			7.1%	17.0%	16.6%			16.9%				10.3%
23	Avg Pay	93,061	102,672				54,311	89,665							
24	New Employees	-	9				117	256							
25	New Employees Pay	-	924,047				6,354,382	22,954,260							
26	2027 Wage Base	174,861,074	327,215,348				120,298,763	257,987,323							
27	Wage Inc %	3.0%	3.0%				3.0%	3.0%							
28	Increase in Wages	5,245,832	9,816,460				3,608,963	7,739,620							
29	2027 Wages	180,106,906	337,031,808				123,907,726	265,726,943							
30	Contribution %	5.6%	5.4%				4.6%	4.0%							
31	2027 Contribution	9,997,384	18,128,952	24.3%	4,398,774	14,396,158	5,684,361	10,584,071	24.3%	2,568,099	8,252,460	15,681,746	28,713,023	6,966,872	22,648,618
32	% Increase	3.0%	3.3%			3.1%	8.7%	13.1%			10.1%				5.5%

DTE Gas Response to DR AGDG-2.25a

DTE Gas Company
Case No. U-21973
AGDG-2.25a Savings Plan Projected Test Year Summary

Case No. U-21973
Requestor AG
Question AGDE-2.25a
Respondent M. Fix

($000's)

Line No		(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	
			2024											
			Recorded	Fofeitures Adj	VSIP Savings	Lag Hiring	Normalized	Inc/(Dec)	2025	Inc/(Dec)	2026	Inc/(Dec)	2027	Average
1		Funding	17,747		(153)	251	17,845	1,609	19,454	2,009	21,464	1,185	22,649	
2		Forfeitures	(771)	373			(398)	67	(331)	(10)	(340)	(10)	(351)	
3		Other	3				3	-	3	-	3	-	3	
4			16,979	373	(153)	251	17,450	2,147	19,127	1,999	21,126	1,175	22,301	
5		Transfers												
6			16,979	373	(153)	251	17,450	1,676	19,127	1,999	21,126	1,175	22,301	
7														
8		% Capitalized	39.72%	39.72%	39.70%	39.70%	39.72%		39.7%		39.7%		39.7%	
9														
10		Capitalized	(6,745)	(148)	61	(100)	(6,932)		(7,597)		(8,392)		(8,858)	
11														
12		Expense	10,235	225	(92)	151	10,519	1,011	11,529	1,205	12,734	708	13,443	
13														
14		Projected Annual % Change							9.6%		10.5%		5.6%	8.5%

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-2.25b

Respondent: M. A. Fix

Page: 1 of 1

Question: Refer to Exhibit A-13, Schedule C5.9, page 2, regarding the $2.7 million increase in expense for the savings plan. Please:

b. Provide a schedule in Excel showing for each of the ten years ending in 2025 the savings plan expense and the number of savings plan participants.

Answer: Please see attachment entitled "U-21973 AGDG-2.25b Employee Savings Plan Expense and Participants 2016-2025"

Attachment: U-21973 AGDG-2.25b Employee Savings Plan Expense and Participants 2016-2025

DTE Gas Company											Case No.	U-21973
Case No. U-21973											Requestor	AG
AGDG-2.25b											Question	AGDE-2.25b
Employee Savings Plan Participants and Expense: 2016-2025											Respondent	M. S. Cooper
($000)												
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
Line No.	**Description**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	
1	Cash Contributionss	10,001	11,217	12,045	13,600	14,745	15,772	16,757	17,157	18,264	17,753	
2	Accrued Contributions	47	9	45	90	135	86	22	34	(517)	786	
3	Total Contributions	10,048	11,226	12,090	13,690	14,880	15,858	16,779	17,191	17,747	18,539	
4	Forfeitures	(123)	(187)	(138)	(206)	(191)	(201)	(516)	(348)	(771)	(496)	
5	Other	23	5	4	2	4	7	10	1	3	(3)	
6	Total Savings Plan Costs	9,948	11,044	11,955	13,486	14,693	15,665	16,274	16,845	16,979	18,040	
7												
8	Proportion Expensed	66.8%	70.7%	69.1%	67.1%	63.6%	64.0%	63.7%	60.4%	60.3%	61.9%	
9												
10	Savings Plan Expense	6,646	7,810	8,256	9,054	9,340	10,021	10,368	10,171	10,235	11,161	
11												
12	Annual % Change											
13	Total Savings Plan Costs		11.0%	8.3%	12.8%	9.0%	6.6%	3.9%	3.5%	0.8%	6.2%	
14												
15	Savings Plan Expense		17.5%	5.7%	9.7%	3.2%	7.3%	3.5%	(1.9%)	0.6%	9.1%	
16												
17	Gas Participants											
18	In Lieu of Pension	346	415	655	859	881	1,009	1,115	1,132	1,155	1,177	
19	401(k)	1,561	1,598	1,667	1,838	1,835	1,856	1,846	1,750	1,758	1,733	
20												
21	LLC Participants											
22	In Lieu of Pension	967	1,300	1,455	1,575	1,611	1,958	2,314	2,042	1,978	1,941	
23	401(k)	3,009	3,018	3,033	3,102	3,020	3,051	3,332	3,237	3,091	2,786	

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Case No. U-21973
Exhibit AG-54
March 13, 2026

Employee Savings Plan Expenses -Reduced Inflation Rate
(Thousands of Dollars)

Line	Caption	2020	2021	2022	2023	2024	2025	Reference
	(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
	Historic Cost Information							
1	Actual Savings Plan Expenses	$ 9,340	$ 10,021	$ 10,388	$ 10,171	$ 10,235	$ 11,161	Note 1
2	Annual percent change		7%	4%	-2%	1%	9%	
3	Avg. Annualized Cost Increase				***3.63%***			

		Actual*	Projected**			
	Projected Cost Information	2025	2026	2027	Test Year	
4	Actual 2025 Escalated 3.63% per Year	11,161	11,566	11,986	$ 11,881	
5	Company Expense Estimate				13,266	Ex. A-13, Sch. C5.9, p. 2 (L5)
6	***Reduction in Employee Savings Plan Expense and O & M***				***$ (1,385)***	Line 3 less Line 4

Notes
1 Exhibit AG-53 includes DR AGDG 2.25b.
* From Line 1 Above
** 2025 expenses escalated by 3.63% each year with Test Year equal to 25% of 2026 and 75% of 2027

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-7.321
Respondent: M. S. Cooper
Page: 1 of 1

Question: Refer to Exhibit A-13, Schedule C5.6, page 1, sponsored by Mr. Cooper. For each of the expenses for New Hire VEBA, Employee Savings Plan, and Active Healthcare on line 11, please provide the expense forecasted by the Company in Case U-21291 and the actual expense for the same period in Excel.

Answer: Assuming the question is referring to Schedule C5.9 not C5.6, please see attachment entitled "U-21973 AGDG-7.321 VEBA, ESP and Healthcare U-21291".

The projected period in Case No. U-21291 did not include the impacts of the Voluntary Separation Incentive Plan implemented in 2024. Thus, total employees allocable to DTE Gas as of September 30, 2025, were about 5% lower than in 2022. The savings in VEBA, ESP and Healthcare expense due to this reduction in employees is estimated to be almost $2 million.

Further, the projected Active Healthcare expense included a Constant Dollar adjustment of $1.3 million and $1.5 million of COVID related costs that did not recur in 2025.

Attachment: U-21973 AGDG-7.321 VEBA, ESP and Healthcare U-21291

Michigan Public Service Commission
DTE Gas Company
Projected Operation and Maintenance Expenses
Projected 12 Month Period Ending September 30, 2025
($000)

Line No.	Description	(a)	(b) U-21291 Schedule A-13, C5.9 Projected Period Ending 9/30/25	(c) Actual 9/30/25
	Post-Retirement Benefits			
1	New Hire Retiree VEBA		3,256	2,211
2	Employee Savings Plan		13,166	11,165
3	Subtotal Post-Retirement		16,422	13,376
4	**Active Healthcare**			
5	Medical Expenses		20,583	16,614
6	Dental Expenses		1,332	1,155
7	Vision Expenses		126	92
8	Subtotal Active Healthcare		22,041	17,861

U-21973 AGDG-7.321 VEBA, ESP and Healthcare U-21291

Active Healthcare Expenses -Reduced Inflation Rate
(Thousands of Dollars)

Line	Caption	2019	2020	2021	2022	2023	2024	2025	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Historic Cost Information								
1	Gross Actual Medical, Dental & Vision	$ 26,201	$ 28,525	$28,143	$ 28,475	$ 27,991	$ 27,637	$ 29,610	Note 1
2	Annual growth (decline) in health care costs		8.9%	-1.3%	1.2%	-1.7%	-1.3%	7.1%	
3	Avg. Annualized Cost Increase					***2.20%***			

		Actual*	Projected**			
	Projected Cost Information	2025	2026	2027	Test Year	
4	Actual 2025 Escalated 2.2% per Year	29,610	30,261	30,927	$ 30,761	
5	Less Allocation to Costs Capitalized @ 39%	(11,548)	(11,802)	(12,062)	(11,997)	
6	Net Cost in O & M	$ 18,062	$ 18,459	$ 18,866	$ 18,764	Line 3 less Line 4
7	Company Expense Estimate				20,759	Note 2
8	***Reduction in Healthcare Expense and O & M***				***$ (1,995)***	Line 5 less Line 6

Notes
1 Exhibit AG-56 includes DR AGDG 2.24 (a).
2 Exhibit A-13, Sch. C5.9, page 2, line 11
* Per AGDG 2.24, parts (a) and (c)
** 2025 expenses escalated by 2.2% each year with Test Year equal to 25% of 2026 and 75% of 2027

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.24a
Respondent: M. S. Cooper
Page: 1 of 1

Question: Regarding Active Employee Medical, Dental, and Vision expenses shown in Exhibit A-13, Schedule C5.9, page 2, please provide the following information for each year 2019 through 2025 in Excel:

a. The gross actual medical, dental, and vision expenses for DTE Gas and DTE Electric, separately, for each year and with the Corporate Services LLC expenses allocated to each utility.

Answer: DTE Gas objects to this request for the reason that the information sought is not relevant or proportional to the needs of this case. Specifically, this request seeks information regarding DTE Electric that is outside the scope of this case and does not have the tendency to make the existence of any fact that is of consequence to the determination of this action more probable or less probable. In addition, DTE Gas objects for the reason that the request is unduly burdensome and overly broad. Subject to these objections and without waiving these objections, DTE Gas answers as follows:

Please see attachment entitled "U-21973 AGDG-2.24a Active Healthcare DTE Gas 2019-2025", which reflects the total costs prior to the impact of costs capitalized.

Attachment: U-21973 AGDG-2.24a Active Healthcare DTE Gas 2019-2025

DTE Gas Company
Case No. U-21973
AGDG-2.24a
Active Heath Care DTE Gas 2019-2025
($000)

Case No. U-21973
Requestor AG
Question AGDG-2.24a
Respondent M. S. Cooper

Line No.	Description	2019 Gas	2019 Electric	2019 LLC	2019 Total	2020 Gas	2020 Electric	2020 LLC	2020 Total	2021 Gas	2021 Electric	2021 LLC	2021 Total	2022 Gas	2022 Electric	2022 LLC	2022 Total	2023 Gas	2023 Electric	2023 LLC	2023 Total	2024 Gas	2024 Electric	2024 LLC	2024 Total	2025 Gas	2025 Electric	2025 LLC	2025 Total
(a)		(b)	(c)	(d)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)
1	**DTE Gas Active Healthcare Costs**																												
2	Medical Expenses	18,416	137	5,943	24,496	19,861	185	6,759	26,805	17,513	140	8,507	26,160	18,015	154	8,409	26,579	18,635	222	7,149	26,007	18,129	187	7,386	25,702	19,886	138	7,545	27,568
3	Dental Expenses	1,036	8	432	1,476	1,006	8	479	1,493	1,277	10	545	1,832	1,180	11	526	1,717	1,262	16	548	1,826	1,236	13	523	1,772	1,318	9	544	1,871
4	Vision Expenses	212	1	15	228	210	2	15	227	132	1	17	151	164	1	15	179	142	2	15	159	145	1	16	163	150	1	19	170
5	Total Active Healthcare	19,665	146	6,390	26,201	21,077	195	7,253	28,525	18,922	151	9,069	28,143	19,359	166	8,950	28,475	20,040	240	7,712	27,991	19,511	201	7,925	27,637	21,354	148	8,107	29,610

Line		AIP					REP					2024 AVG.
		2020	2021	2022	2023	2024	2020	2021	2022	2023	2024	
1	**Customer Satisfaction**											
2	Customer Satisfaction Index	0.0%	0.0%	100.0%	0.0%	75.0%	0.0%	0.0%	100.0%	0.0%	83.3%	
3	& Net Promoter Score											
5	Customer Satisfaction											
6	Imoprovement (DPMO)	175.0%	N/A	N/A	N/A	N/A	150.0%	N/A	N/A	N/A	N/A	
8	Customer Satisfaction											
9	Improvement (+1 PMO)	0.0%	N/A	N/A	N/A	N/A	0.0%	N/A	N/A	N/A	N/A	
11	MPSC Customer Complaints	175.0%	0.0%	81.8%	0.0%	N/A	150.0%	0.0%	87.9%	0	N/A	
13	**Employment Engagement**											
14	DTE Gas Employee Engagement											
15	Gallup	57.1%	62.5%	117.3%	139.5%	87.5%	N/A	N/A	N/A	N/A	N/A	
17	DTE Gas OSHA Recordable											
18	Incident Rate	175.0%	140.0%	157.1%	0.0%	50.7%	150.0%	126.7%	138.1%	0.0%	67.1%	
20	DTE Gas OSHA DART Rate or High											
21	Energy Serious Injury/Fatality	131.3%	0.0%	126.0%	0.0%	100.0%	120.0%	0.0%	116.7%	0.0%	100.0%	
23	**Operating Excellence**											
24	Gas Open Leak Balance &											
25	Gas Distrib. System Imprvmt.	0.0%	175.0%	113.8%	122.2%	117.1%	0.0%	150.0%	109.2%	114.8%	111.4%	
27	Gas Distrib. Response Time	160.0%	127.3%	120.5%	53.0%	87.0%	140.0%	118.2%	113.8%	68.6%	91.4%	
29	Lost and Unaccounted For Gas	25.0%	N/A	N/A	N/A	N/A	50.0%	N/A	N/A	N/A	N/A	
31	Gas Compression Reliab.	175.0%	N/A	N/A	N/A	N/A	150.0%	N/A	N/A	N/A	N/A	
33	Gas Damage Prevention	60.6%	N/A	N/A	N/A	N/A	73.8%	N/A	N/A	N/A	N/A	
35	% of HCA Accessible by ILI	N/A	175.0%	175.0%	175.0%	175.0%	N/A	150.0%	150.0%	150.0%	150.0%	
37	% of High Pop. Miles w/TVC											
38	Pressure Test Records Remed.	N/A	115.6%	175.0%	175.0%	100.0%	N/A	110.4%	150.0%	150.0%	100.0%	
40	Meter Assembly Check Backlog	118.2%	N/A	N/A	N/A	N/A	112.1%	N/A	N/A	N/A	N/A	
42	Less Than Threshold	3	3	0	4	0	3	3	0	4	0	
43	Btw. Threshold & Less Than Target	3	1	1	1	4	2	0	1	1	3	
44	Target	0	0	1	0	2	0	0	1	0	2	
45	Btw. Target and Maximum	3	3	5	2	2	3	3	4	1	2	
46	Maximum	4	2	2	2	0	4	2	2	2	0	
47	Total	13	9	9	9	8	12	8	8	8	7	
49	Sum	12.52	7.95	11.67	6.65	7.92	10.96	6.55	9.66	4.83	7.03	
51	Number of Measures	13	9	9	9	8	12	8	8	8	7	
52	Average	0.96	0.88	1.30	0.74	0.99	0.91	0.82	1.21	0.60	1.00	
54	Performance Measures Achieved at											
55	Target or Better	7	5	8	4	4	7	5	7	3	4	
56	Percentage of Measures (Target +)	**53.8%**	**55.6%**	**88.9%**	**44.4%**	**50.0%**	**58.3%**	**62.5%**	**87.5%**	**37.5%**	**57.1%**	**59.6%**

Source: DR AGDG-3.97b attachments.

O&M Reductions - Related to Shared Asset Charges

Thousands of Dollars

Line	Caption or Description	2025	2026	2027	Projected Test Year	Notes
	(a)	(b)	Ic)	(d)	(e)	(f)
	Company Information Provided					
1	Company Projection in Rate Case	$ 47,036			$ 52,197	Note A
2	Actual 2025 per Company	46,199				Note B
3	2025 Difference	$ 837				
	Attorney General Projection					
4	Actual 2025 Expense from Above	$ 46,199				
5	Inflation for 2026 at 2.4%	1,109				Note C
6	Base level for 2026	$ 47,308	$ 47,308			
7	Inflation for 2027 at 2.3% for 9 of 12 months		816			Note C
8	Base level for 2027		$ 48,124	$ 48,124		
9	Projected Test Year Expense (25% of 2026 & 75% of 2027)				$ 47,920	
10	Difference in Rents -Shared Asset				$ (4,277)	
11	Rents - Shared Assets Amortization				(167)	L3 x 20%
12	**Total Reductions Related to Shared Assets and O&M**				**$ (4,445)**	

A From Exhibit A-13, Schedule C5.6, page 3, line 2
B Discovery Response AGDG - 2.23 a&b attachment (tab A-13, C5.6).
C Exhibit AG-2 includes DR AGDG 1.4a.

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-2.21b
Respondent: J. E. Sparks
Page: 1 of 1

Question: Refer to Exhibit A-13, Schedule C5.7, on Uncollectible Accounts Expense. Please:

b. Explain what the Charges to Direct Expense on line 6 are for and why they are additive to Net Charge-Offs. If the 2025 amount is higher than zero, explain what it consists of.

Answer: In 2022 and 2023, the amounts in line 6 arose from company matches to energy assistance provided to customers in those years. This was a result of collaboration with the Michigan Department of Health and Human Services (MDHHS) where the Company leveraged matching funds to alleviate arrears for vulnerable customers. In the absence of these matches, the customer dollars would have been write-offs in those years.

The 2025 amount is less than zero.

Attachment: None

Exhibit AG-61

CONFIDENTIAL

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-5.176a
Respondent: E. D. Janness
Page: 1 of 1

Question: Refer to lines 21-25 on page 28 of Mr. Janness' direct testimony on the Company's decision to reduce the 2024 Gas Renewable Program spending after the U-21291 order was issued on November 7, 2024, thereby postponing retirements for the 236.6 miles of installed main to avoid compromising grid reliability. Please:

a. Identify the number of miles of main retirements that the Company postponed in 2024 and in which months.

Answer: The Company postponed approximately 13 miles of main retirement in November and December of 2024.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-5.176b
Respondent: E. D. Janness
Page: 1 of 1

Question: Refer to lines 21-25 on page 28 of Mr. Janness' direct testimony on the Company's decision to reduce the 2024 Gas Renewable Program spending after the U-21291 order was issued on November 7, 2024, thereby postponing retirements for the 236.6 miles of installed main to avoid compromising grid reliability. Please:

b. When retiring legacy mains with replacements, does the Company remove the legacy mains from their underground locations by excavating them out or does the Company leave the old mains in place. If physically removed, provide the number of miles removed in each year 2023 to 2025 in comparison to the total number of miles retired.

Answer: The Company leaves the old mains in place.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-5.177a_Supplemental
Respondent: E. D. Janness
Page: 1 of 1

Question: Refer to Table 3 on page 29 of Mr. Janness' direct testimony on the Main Renewal costs and miles. Please:

a. Expand this table to include the actual information for 2025 and provide it in Excel.

Answer: See table below.

Table 3. Main Renewal Costs and Miles

$ In Millions	Capital Expenditures	Miles Retired	Miles Installed	Cost Per Installed Mile
2023 (Actual)	$294.10	224	273.3	$1.08
2024 (Actual)	$296.60	177	236.6	$1.25
2025 (Prelim)	$271.72	158.4	183.3	$1.48

*Preliminary figured to be reconciled and finalized upon submission of our annual March 31st report. Does not include MAC MMO or Supplemental MMO.

Attachment: None

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-5.184a
Respondent: E. D. Janness
Page: 1 of 1

Question: Refer to Table 6 on page 39 of Mr. Janness' direct testimony on miles of legacy main by level of complexity. Please:

a. Provide the same information in Excel for each year 2015, 2020, 2022-2025, and forecasted for 2026 and 2027. Provide also the related cost per mile. If there are miles of main that are not complex for each year, identify those miles and the related cost per mile.

Answer: This table is meant to be a guideline for how work is spread when deciding scope in a given year. Use of this designation began in 2024. Please see attached for the actual miles of each category for 2024 and 2025 as well as a forecast for 2026. 2027 scope has not been determined but the table is the guideline.
There is not a specific cost per mile for complexity as each complex project has its own set of factors with varying costs to earn that designation.

Attachment: U-21973 AGDG-5.184a-01 Table 6 Expanded

DTE Gas Company
EDJ Testimony Table 6 Expanded
AGDG-5.184a

Project Type in Miles	SEMI 2024	*Prelim SEMI 2025	Planned SEMI 2026	Forecast SEMI 2027	GRMI 2024	*Prelim GRMI 2025	Planned GRMI 2026	Forecast GRMI 2027
High Complexity	5	3	13	11	22	3	6	4
Medium Complexity	113	113	66	107	35	35	27	35
Total PRA	118	116	79	118	58	38	33	39
Muni/Field/Coor Recom	0.8	2	4	2		2		2
Total GRP	119	118	83	120	58	40	33	41

*Preliminary figured to be reconciled and finalized upon submission of our annual March 31st report.

MPSC Case No: U-21973
Requester: AG
Question No.: AGDG-5.211a
Respondent: E. D. Janness
Page: 1 of 1

Question: Refer to Exhibit A-12, Schedule B6.1. Please:

a. Expand this schedule to include 2025 actual information and provide it in Excel.

Answer: DTE Gas objects to this request to the extent that it seeks confidential and/or material non-public information. Without waiving said objection and subject thereto:

Please see attached. 2025 actuals are preliminary and unaudited prior to the filing of the Company's SEC Form 10-K.

Attachment: NDA U-21973 AGDG-5.211a-01 Exhibit A-12 B6.1 2025 Actuals & Expanded

Michigan Public Service Commission Case No.: U-21973
DTE Gas Company Exhibit: A-12
Actual Capital Cost of IRM Schedule: B6.1
Compared to Targeted Levels 2016-2024 Witness: E. D. Janness
($000s) Page: 1 of 1

Line No.	(a) Description	(b) Planned	Planned Units	(c) Actual	Actual Units	(d) Variance
	2016					
1	Main Renewal Program	$ 62,500	82	$ 85,036	93	$ 22,536
2	Meter Move Out	22,700	12,790	26,025	7,716	3,325
3	Pipeline Integrity	7,818	-	10,960	-	3,142
4	Total IRM	$ 93,018		$ 122,020		$ 29,002
	2017					
5	Main Renewal Program	$ 93,800	123	$ 120,021	134	$ 26,221
6	Meter Move Out	22,700	12,790	22,370	13,338	(330)
7	Pipeline Integrity	11,110	-	12,982	-	1,872
8	Total IRM	$ 127,610		$ 155,373		$ 27,763
	2018					
9	Main Renewal Program	$ 105,650	123	$ 140,856	157	$ 35,206
10	Meter Move Out	22,900	14,790	23,860	13,926	960
11	Pipeline Integrity	12,040	-	13,587	-	1,547
12	MAC MMO	2,625	-	5,045	2,543	2,420
13	Total IRM	$ 143,215		$ 183,347		$ 40,132
	2019					
14	Main Renewal Program	$ 169,700	123	$ 197,310	183	$ 27,610
15	Meter Move Out	22,700	14,790	28,651	14,808	5,951
16	Pipeline Integrity	11,120		16,976		5,856
17	MAC MMO	20,300	8,000	15,837	8,042	(4,463)
18	Total IRM	$ 223,820		$ 258,774		$ 34,954
	2020					
19	Main Renewal Program	$ 193,000	206	$ 226,868	206	$ 33,868
20	Meter Move Out	22,700	14,790	35,120	15,658	12,420
21	Pipeline Integrity	11,120		11,332		212
22	MAC MMO	20,300	8,000	17,473	8,016	(2,827)
23	Total IRM	$ 247,120		$ 290,794		$ 43,674
	2021					
24	Main Renewal Program	$ 232,400	206	$ 235,741	214	$ 3,341
25	Meter Move Out	22,700	14,790	26,109	15,745	3,409
26	Pipeline Integrity	11,120		12,074		954
27	MAC MMO	16,500	8,000	21,965	8,138	5,465
28	Total IRM	$ 282,720		$ 295,888		$ 13,168
	2022					
29	Gas Renewal Program	$ 255,100	206	$ 292,024	222	$ 36,924
30	Pipeline Integrity	11,120		20,367		9,247
31	MAC MMO	21,040	8,000	23,113	8,353	2,073
32	Total IRM	$ 287,260		$ 335,504		$ 48,244
	2023					
33	Gas Renewal Program	$ 255,100	206	$ 292,792	224	$ 37,692
34	Pipeline Integrity	11,120		27,007		15,887
35	MAC MMO	21,040	8,000	25,674	8,621	4,634
36	Total IRM	$ 287,260		$ 345,474		$ 58,214
	2024					
33	Gas Renewal Program	$ 255,100	190	$295,518	177	$ 40,418
34	Pipeline Integrity	11,120		16,792		5,672
35	MAC MMO	21,040	8,000	25,100	6,442	4,060
36	Total IRM	$ 287,260		$337,410		$ 50,150
	2025					
33	Gas Renewal Program	$ 287,545	190	$295,448	158	$7,903
34	Pipeline Integrity	23,060		33,557		10,497
35	Regulator Station Replacement Program	-	-	6,923	-	6,923
36	Cathodic Protection	-		10,432		10,432
37	Total IRM	$ 310,605		$346,360		$35,755

(1) Expenditures listed do not include vehicle depreciation or annual incentives which were disallowed from IRM
(2) 2025 units are preliminary and will be reconciled and finalized upon the submission of our annual March 31st Report.

Michigan Public Service Commission
DTE Gas Company

Exhibit AG-63
Case No. U-21973
Date: March 13, 2026

AG Calculation of Overall Cost of Capital for IRM with 7.12% ROE rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Capital Structure							
Line No.	Description	Cost Rate Source from Exhibit A-14 Schedule	13 Mo. Avg. Amount (1)	% Amount of Permanent Capital	% Amount of Total Capital	Cost Rate %	Weighted Cost of Permanent Capital (%)	Weighted Cost of Total Capital (%)	Pre-tax Multiplier	Pre-tax Cost of 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	2,749,081	50.00%	39.59%	7.12%	3.56%	2.82%	1.355	3.82%
3	Sub-Total		$ 5,498,161	100.00%			5.78%			
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		-		- %	7.12%		- %	1.355	- %
10	Total JDITC		$ -							
11	Total		$ 6,943,963		100.00%			4.73%		5.73%

Source: AGDG-7.300c U-21291 Appendix D Case No. U-21291

Computation of Revenue Deficiency for Projected Test Year Ending September 30, 2027

($000)

Line	Description	Company Filed Amount	AG Recommended Adjustments	Revised Amount
	(a)	(b)	(c)	(d)
1	Rate Base [1]	$ 8,033,624	$ (157,505)	$ 7,876,119
2	Rate of Return	6.18%	-0.25%	5.93%
3	Income Required	$ 496,132	$ (29,078)	$ 467,054
4	Adjusted Net Operating Income [2]	320,846	65,299	386,145
5	Income Deficiency (Sufficiency)	$ 175,286	$ (94,377)	$ 80,909
6	Revenue Multiplier	1.3547	1.3547	1.3547
7	**Base Revenue Deficiency (Sufficiency)**	**$ 237,460**	**$ (127,853)**	**$ 109,607**
8	Impact due to IRM Roll-in to Rate Base	(74,798)	-	(74,798)
8	**Net Revenue Deficiency / (Sufficiency)**	**$ 162,662**	**(127,853)**	**$ 34,809**

[1] Rate Base Adjustments Exhibit AG-18

[2] AG adjustments to Operating Income: Increase (Decrease)

			Source
Revenue		$ 24,271	Testimony
O&M Expenses		$ 58,855	Exh. AG-41
Property Tax		$ 1,007	Exhibit AG-18
Depreciation Expense		$ 5,328	Exhibit AG-18
Total		$ 89,461	
Effective Tax Rate (1-1/1.3547)	26.18%		
Taxes		(23,424)	
Interest Synchronization on Capital Adjustments		(738)	RevDef-WP1
Adjusted Net Operating Income		$ 65,299	

PROOF OF SERVICE - U-21973

The undersigned certifies that a copy of the ***Attorney General's PUBLIC Direct Testimony and Exhibits of Sebastian Coppola*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 13th day of March 2026.

/s/ Joel King

Joel B. King

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