STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21534

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

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of
Attorney General Dana Nessel

July 26, 2024

TABLE OF CONTENTS

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, and other proceedings. As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, I have been intricately involved in regulatory proceedings related to gas cost recovery cases, gas purchase strategies, rate case filings and power plant cost analysis. I have also supported other witnesses in testimony before the MPSC in various rate setting and other regulatory proceedings.

Q. WHAT EXPERIENCE DO YOU HAVE WITH ELECTRIC UTILITIES?

A. I have performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operations and maintenance expenses, cost allocations, cost of capital, cost of service and rate design, various cost tracking mechanisms and integrated resource plans. In addition, I have performed analyses of power costs and filed testimony in power supply cost recovery mechanisms, including reconciliation of annual power supply costs.

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

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:

- 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 the Michigan Gas Utilities Corporation (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 Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (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 DTE Electric Company (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 CECo 2022 PSCR reconciliation in case No. U-21049.
- 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.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 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 DTE Electric Company (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.
- 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.

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 Attorney General to perform an independent analysis of DTE Electric Company's ("Company" or "DTEE") Electric Rate Case filing in Case No. U-21534. 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 level of proposed Rate Base and Capital Expenditures
2. The Company's Cost of Capital
3. Working Capital
4. The level of Operations and Maintenance expenses
5. The Adjusted Revenue Deficiency

The absence of discussion on other matters in my testimony should not be taken as an indication that I agree with those aspects of DTEE's rate case filing. The narrow focus of my testimony is, instead, a consequence of focusing on certain 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 Blue Chip Report with CPI Rates
3. Exhibit AG-3 Emergent Replacements 2018-2023
4. Exhibit AG-4 CONF EV Utility Make Ready Attachments
5. Exhibit AG-5 Housing Starts

6. Exhibit AG-6 I-375 Relocation
7. Exhibit AG-7 Tree Trim Surge Cost Savings
8. Exhibit AG-8 Steam Generation Actual Capex 2019-2023
9. Exhibit AG-9 CONF Nuclear Plant Security System
10. Exhibit AG-10 CONF Nuclear Plant Radio System
11. Exhibit AG-11 Nuclear Capital Expenditures 2018-2023
12. Exhibit AG-12 Nuclear Project Discovery for Projects $3MM+
13. Exhibit AG-13 Discovery Customer Service IT Projects $3MM+
14. Exhibit AG-14 Discovery IT Project 3MM+
15. Exhibit AG-15 IT Capex 2018-2023
16. Exhibit AG-16 Discovery Corporate Facilities and Projects 3MM+
17. Exhibit AG-17 Corporate Capex 2018-2023
18. Exhibit AG-18 Capex, Rate Base Depreciation, Property Tax Adjustments
19. Exhibit AG-19 Deferred Ludington Costs
20. Exhibit AG-20 Working Capital Adjustment to Deferred Incentive Comp
21. Exhibit AG-21 DTEE Incentive Comp Performance Metric Results
22. Exhibit AG-22 TOD Cost Deferral and Cost Detail
23. Exhibit AG-23 Customer Power Outages from Trees
24. Exhibit AG-24 Detroit Tree Trim Academy Participation
25. Exhibit AG-25 Tree Trim Surge Return on Regulatory Asset
26. Exhibit AG-26 Overall Cost of Capital
27. Exhibit AG-27 Cost of Common Equity-Summary
28. Exhibit AG-28 Cost of Common Equity-DCF
29. Exhibit AG-29 Cost of Common Equity-CAPM
30. Exhibit AG-30 Cost of Common Equity-Risk Premium
31. Exhibit AG-31 Electric ROE Decisions by Regulatory Commissions
32. Exhibit AG-32 Midwest Utilities ROEs
33. Exhibit AG-33 Peer Group Analysis
34. Exhibit AG-34 Market to Book Ratios
35. Exhibit AG-35 Moody’s Cash Flow Coverage Ratio

36. Exhibit AG-36 Value Line Article on Volatility vs. Risk
37. Exhibit AG-37 O&M Adjustments Summary
38. Exhibit AG-38 O&M Inflation Adjustment
39. Exhibit AG-39 O&M Steam Generation
40. Exhibit AG-40 O&M Tree Trim Surge Program Savings
41. Exhibit AG-41 Uncollectible Accounts Expense
42. Exhibit AG-42 O&M Injuries and Damages
43. Exhibit AG-43 O&M Active Health Care
44. Exhibit AG-44 O&M Incentive Compensation
45. Exhibit AG-45 Voluntary Separation Package
46. Exhibit AG-46 Credit Card Information
47. Exhibit AG-47 Corporate Aircraft Costs
48. Exhibit AG-48 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 $456.4 million. This rate increase represents an overall increase in rates of 8.2%, with a 9.6% increase to residential customers. As a result of the rate case adjustments that I propose in my testimony, I determined that the Company has a revenue deficiency of $139.5 million. Based on this amount of rate increase, the average residential customer should see an increase of approximately 2.5% in their total bill.

It is noteworthy to point out that for the historical test year, the Company reported a revenue excess of $80.5 million.

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

1. I propose a lower level of Operations and Maintenance expenses of $123.5 million for the test year.
2. Along with other AG witnesses, I have included a reduction in capital expenditures of $1.018 billion and a reduction in rate base of $783.9 million, including a reduction in working capital of $25.7 million, for a reduction in revenue requirement of $60 million.
3. I propose a reduction in depreciation expense of $40.8 million pertaining to the proposed reductions in capital expenditures.
4. I propose a reduction in property tax expense of $12.3 million pertaining to the proposed reductions in capital expenditures
5. I recommend an authorized rate of return on equity of 9.85% in comparison to the Company's proposed ROE rate of 10.50%, for a reduction in the revenue deficiency of $75.5 million.
6. I recommend that the Commission reject the addition of $87 million to the Tree Trimming Surge program for 2025 and reduce the return on the regulatory asset by $8.9 million to reflect a return rate based on the short-term debt.

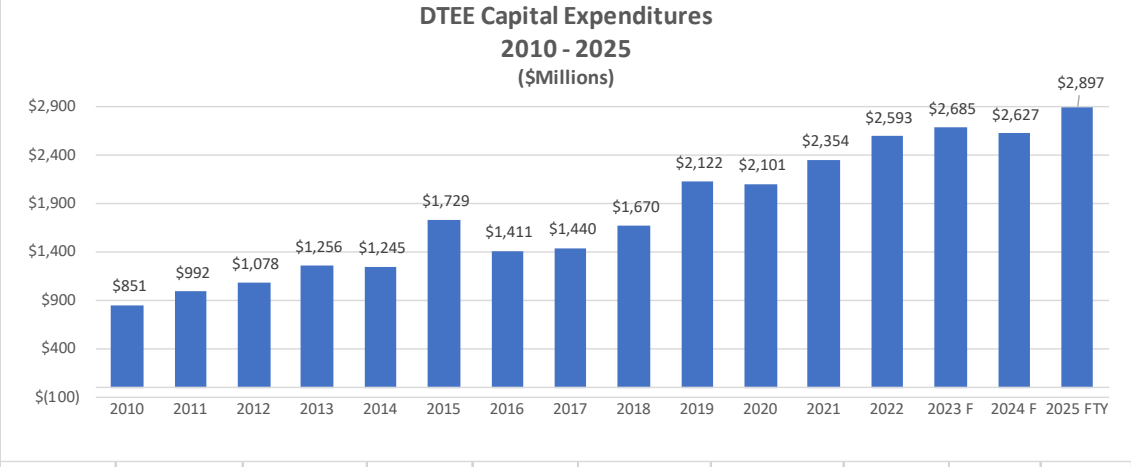
The remainder of my testimony provides further details and support for these summary conclusions and recommendations.

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, DTEE has proposed capital expenditures of $2.7 billion for 2023, $2.6 billion for 2024, and an additional $2.9 billion for 2025, including expenditures under the Infrastructure Recovery Mechanism (IRM). The total proposed capital expenditures over this 36-month period are $8.2 billion.[1] These expenditures follow capital expenditures of $4.9 billion made during the prior two years in 2021 and 2022.[2] 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.

Table 1



[1] Exhibit A-12, Schedule B5 and Exhibit A-33, Schedule X1.
[2] DR AGDE-3.129.

Until 2011, the Company was able to keep capital expenditures below $1 billion annually. Fifteen year later, the level of annual capital expenditures has nearly tripled.

The capital expenditures have fueled an alarming increase in rate base. As shown below in Table 2, rate base has been growing at high-single digit to double digit rates in recent years and the Company is proposing to increase rate base again in this rate case by 16%, to $22.1 billion. The proposed level of rate base in this rate case is more than double the amount of rate base the Company had nearly 10 years ago in 2013.

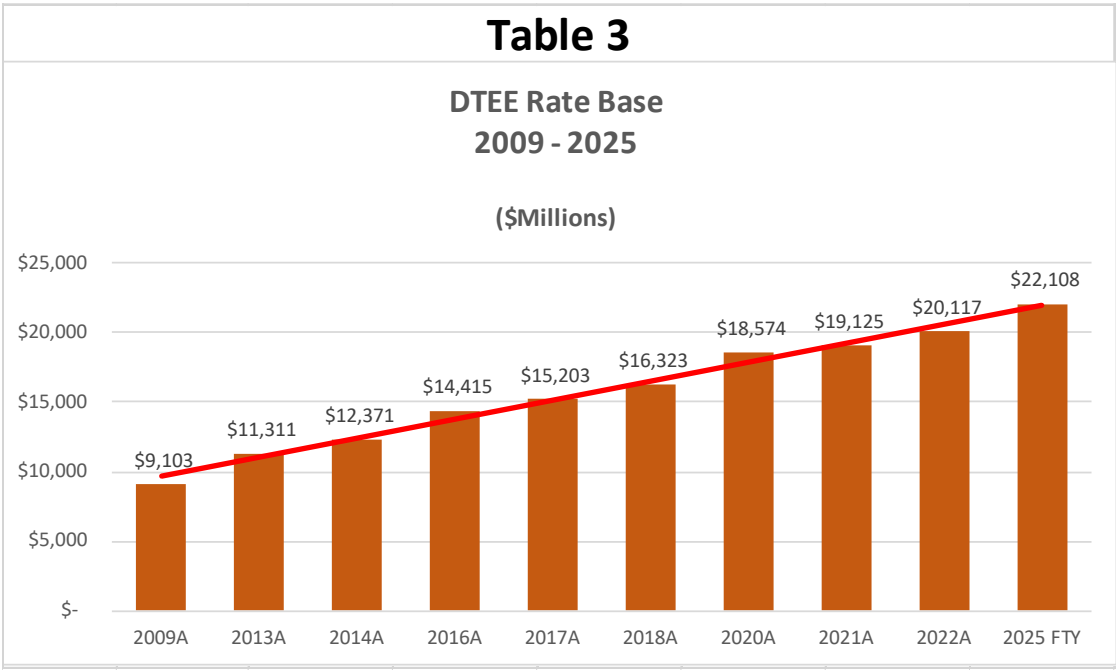
Table 2
DTE Electric Rate Base Growth
2009 to Projected 2025 Test Year

Rate Base Year	2009A	2013A	2014A	2016A	2017A	2018A	2020A	2021A	2022A	2025 FTY
Docket No.	U-16472	U-17767	U-18014	U-18255	U-20162	U-20561	U-20836	U-21297	U-21534	U-21534
Rate Base [1] (Millions)	$ 9,103	$ 11,311	$ 12,371	$ 14,415	$ 15,203	$ 16,323	$ 18,574	$ 19,125	$ 20,117	$ 22,108
Year over Year Change		24%	9%	17%	5%	7%	14%	3%	5%	16%
Cumulative Change over 2009 Rate Base		24%	36%	58%	67%	79%	104%	110%	121%	143%

[1] Historical actual rate base in each docket, except 2025 FTY is a 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, as discussed later in my testimony.

Table 3



Q. WHAT DO YOU BELIEVE IS DRIVING THIS DRAMATIC INCREASE IN CAPITAL EXPENDITURES AND RATE BASE SINCE 2009?

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 and rebuild electrical lines, poles, substations, and related facilities. Some of this work is necessary and must be done. However, the Company has also proposed hundreds of millions of dollars in expensive automation projects, digital projects, a dizzying number of pilot projects, information technology projects, and office remodeling that raise questions about priority spending toward more fundamental electrical infrastructure projects.

Prior to 2012, DTEE 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.

Second and perhaps a bigger driver, the replacement of aging electrical 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 electric utility at an average annual rate of 5% to 7%. Exhibit AG-1 includes pertinent pages from a March 8, 2022 Investor Presentation, which shows this drive to increase earnings through increased capital spending at the utility. It also shows how investors and shareholders have been well rewarded. For a utility such as DTEE with limited sales and revenue growth, 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. DO THE HIGH CAPITAL SPENDING AND OPERATING COST INCREASES SIGNIFICANTLY IMPACT RESIDENTIAL CUSTOMER BILLS?

A. Yes. The Company has proposed to increase residential rates in this rate case by 9.6% over current rates. This increase in annual customer bills poses a significant burden on all residential customers, and especially those with fixed and low income. The compounding effect of large additions to rate base will continue to increase customer rates to unaffordable levels for many customers, particularly those in fixed and lower income brackets. Simply put, this trend is not sustainable for customers. To avoid bill affordability problems in the future, the Company needs to moderate and be more selective in its capital spending in the coming years.

IV. Review of Capital Expenditures

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

A. Yes. I have analyzed the Company's forecasted capital expenditures by major department or functional area and I have identified more reasonable expenditure levels that the Commission should consider.

In projecting adjusted capital expenditures for 2024 and 2025, where applicable I applied an inflation factor to the historical cost base in order to reflect inflationary cost pressure that the Company may face in those years. The inflation factors are 2.4% for 2024 and

2.2% for 2025. These rates reflect the Consumer Price Index-Urban forecast presented in the February 2024 Blue Chip Report.[3]

A. Distribution Plant

As shown on page 1 of Exhibit A-12, Schedule B5.4, the Company forecasted nearly $4.8 billion in capital expenditures for Distribution Plant for the three years 2023 to 2025. After reviewing the testimony of Company witnesses sponsoring testimony in this area, related exhibits, and responses to discovery, I have identified capital expenditure reductions applicable to several capital programs and projects.

1. Emergent Replacements

Q. PLEASE EXPLAIN YOUR ASSESSMENT OF CAPITAL EXPENDITURES FOR EMERGENT REPLACEMENT PROGRAMS.

A. On page 1 of Exhibit A-12, Schedule B5.4, the Company identified three categories of Emergent Replacement Programs: Storm-related, Non-Storm, and Substation Reactive. The total amount of capital expenditures for 2022 for these three programs was $484.7 million. The Company forecasted $531.3 million in capital expenditures for 2023, $492.6 million for 2024, and $506.9 million for 2025. The 2024 amount was reduced by $20.8 million and the 2025 amount was reduced by $21.4 million for expected reductions in emergent capital spending from the anticipated benefit of strategic capital spending.

[3] Exhibit AG-2 includes the February 2024 Blue Chip Report.

The Company arrived at its forecasted level of expenditures for emergent replacement programs by applying retroactive inflation adjustments to historical amounts from 2018 to 2022 and labeling them normalization adjustments on page 3 of Exhibit A-12, Schedule B5.4. It then applied additional forecasted inflation factors for 2023, 2024, and 2025 to the adjusted five-year average cost base to determine the forecasted capital expenditures for the forecasted bridge periods and projected test year. I do not agree with that approach. The Company is simply compounding inflationary increases on top of inflationary increases that already occurred in the historical years.

In response to discovery, the Company disclosed that it inflated 2018 costs by 1.8% for the inflation in 2019 and then again in 2020 by 1.2% for inflation in 2020, and then again by 4.7% for inflation in 2021, and again by 8.0% for inflation in 2022.[4] This process is then repeated for subsequent historical expenditures for 2019 to 2022. This compounding of historical inflation on top of costs that already reflect inflation in the year that the capital expenditures occurred is simply a methodology to increase the base costs on which the Company later adds forecasted inflation for 2023 through 2025. The Company has not provided any evidence that historical costs increased by inflation or by other means in future years. In accepting these compounded inflationary adjustments in recent prior rate cases, the Commission may not have fully understood how the Company had improperly inflated these costs to determine the amount of forecasted capital expenditures included in rate base. However, the Commission should not accept this brazen attempt to inflate

[4] Exhibit AG-3 includes DR AGDE-3.96a and b.

historical capital expenditures by improperly increasing the base on which forecasted costs are calculated in either this or future rate cases.

Although I agree with using a five-year normalization approach to forecast capital expenditures for future years, it should be done using actual capital expenditures from prior years, not by recasting numbers with additional assumed costs that were not incurred based on prior year inflation adjustments. If any inflation was experienced in those prior years, it is reflected in the actual amounts. It is simply an unsupported fabrication to inflate historical costs to arrive at an adjusted historical base and to then further inflate those costs for future years with projected inflation factors. I will also point out that the future inflation rates used by the Company to calculate forecasted Emergent Replacements capital expenditures for 2023, 2024, and 2025 are blended inflation rates consisting of both the CPI and the Company's internal forecasted wage increases. As discussed in more detail in the O&M Expense - Inflation Adjustment section of my testimony, the Commission has previously rejected the use of blended inflation rates.

I will also point out that contrary to the directives by the Commission in Case Nos. U-20561 and U-20836, the Company did not provide an analysis in this rate case of the offsetting effects of significant distribution capital investments on inflationary pressures on Emergent Replacements.

Q. WHAT SPECIFIC ADJUSTMENTS DO YOU RECOMMEND FOR THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE EMERGENT CAPITAL PROGRAMS?

A. To calculate an appropriate forecast of capital expenditures for emergent replacement programs for the 2024 and 2025 forecasted periods, I used the five years historical average capital expenditures from 2019 to 2023 and applied the CPI-based future inflation factors. In response to discovery, the Company provided the actual historical capital expenditures for the three categories from 2019 to 2023.[5] Based on this information, I calculated the forecasted capital expenditures for 2024 using the latest average historical average amount spent and adjusting it by the inflation factors of 2.4% for 2024 and 2.2% for 2025.

For the Storm category, the average 5-year spending was $235,956,000. After adjusting for inflation, the forecasted amount is $241,660,000 for 2024 and $246,976,000 for 2025.[6] In comparison, the Company forecasted $244,066,000 for 2024 and $251,144,000 for 2025. Therefore, I recommend that the Commission remove the difference of $2,406,000 for 2024 and $4,168,000 for 2025 from the Company's forecasted capital expenditures.

For the Non-Storm category, the average 5-year spending was $200,008,000. After adjusting for inflation, the forecasted amount is $204,808,000 for 2024 and $209,314,000 for 2025.[7] In comparison, the Company forecasted $220,275,000 for 2024 and

[5] Id.
[6] $235,956,000 x 1.024 = 241,660,000 x 1.022 = $ 246,976,000.
[7] $200,008,000 x 1.024 = 204,808,000 x 1.022 = $ 209,314,000.

$226,663,000 for 2025. Therefore, I recommend that the Commission remove the difference of $15,467,000 for 2024 and $17,349,000 for 2025 from the Company's forecasted capital expenditures.

For the Substation Reactive category, the average 5-year spending was $41,508,000. After adjusting for inflation, the forecasted amount is $42,504,000 for 2024 and $43,439,000 for 2025.[8] In comparison, the Company forecasted $49,057,000 for 2024 and $50,480,000 for 2025. Therefore, I recommend that the Commission remove the difference of $6,653,000 for 2024 and $7,041,000 for 2025 from the Company's forecasted capital expenditures.

Q. WHAT IS THE TOTAL REDUCTION IN CAPITAL EXPENDITURES FOR EMERGENT REPLACEMENTS THAT YOU RECOMMEND?

A. I recommend that the Commission remove $24,526,000 for 2024 and $28,557,000 for 2025 from the Company's forecasted capital expenditures.

2. Customer Connections and New Load Growth

Q. PLEASE PROVIDE YOUR ASSESSMENT OF FORECASTED CAPITAL EXPENDITURES FOR CUSTOMER CONNECTIONS AND LOAD GROWTH PROJECTS.

[8] $41,508,000 x 1.024 = 42,504,000 x 1.022 = $ 43,439,000.

A. On line 9 of page 1 of Exhibit A-12, Schedule B5.4, the Company included forecasted capital expenditures for Customer Connections and New Load of $216,936,000 for 2023, $206,069,000 for 2024, and $218,608,000 for 2025. Beginning on page 22 of his direct testimony, Company witness Brian Hill discusses how he arrived at the forecasted amounts for 2023, 2024, and 2025. There are two issues with the Company's forecasted capital expenditures in this area. First, the Company applied retroactive historical inflation rates to restate the actual historical number for the three years from 2019 to 2022, before applying the future inflation rates to the adjusted three-year historical average spending. This is the same problem discussed above with Emergent Replacements, where the Company improperly inflates actual historical capital expenditures to create a larger cost base on which to add future inflation adjustments. Mr. Hill also used this faulty approach to forecast capital expenditures for Relocations, Electric System Equipment, NRUC and Improvements Blankets, and General Plant, Tools & Equipment.

In his testimony, Mr. Hill states that the three-year average approach he used in this rate case is consistent with the Commission decision in Case No. U-21297. That statement is incorrect. Although the Commission approved the three-year historical average approach I recommended in that rate case, my historical average did not include any restatement of actual capital expenditures with additional historical inflationary adjustments, as Mr. Hill proposes in his testimony and calculations. The Commission should reject the Company's approach as a change to the previously approved methodology and also because it improperly inflates historical costs. As discussed below, in this rate case, I will use the

same approach to forecast customer connections, new load, relocations, and other capital expenditures previously approved by the Commission in Case No. U-21297.

Second, in his testimony Mr. Hill states that the capital expenditures for Customer Connections and New Load include costs for Utility Make Ready (UMR) for upgrading and installing equipment and facilities at customer premises to support Electric Vehicle chargers under the Transportation Electrification Plan. Although Mr. Hill did not identify those expenditures in his testimony or exhibits, in response to discovery the Company reported that in 2022 it incurred $8,552,844 in capital expenditures for UMR before Contributions In Aid of Construction (CIAC).[9] The Company estimates that CIAC are 15% of the amount spent. After CIAC, the Company incurred net expenditures of $6,439,000 for 2022. For 2023, 2024, and 2025, the Company forecasted UMR capital expenditures of $9,531,029, $14,151,715, and $21,491,850, respectively. Adjusted for the 15% CIAC, the net forecasted amounts are $8,101,000, $12,029,000, and $18,651,000 for 2023, 2024, and 2025, respectively. In my testimony below when forecasting the amount of capital expenditures for Customer Connections and New Load, I excluded the UMR expenditures. I will address those capital expenditures as a separate item.

Q. WHAT SPECIFIC ADJUSTMENTS DO YOU RECOMMEND TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR CUSTOMER

[9] Exhibit AG-4 includes DR AGDE-3.90c.

CONNECTIONS AND NEW LOAD GROWTH, EXCLUDING UMR EXPENDITURES?

A. In response to discovery, the Company provided the actual capital expenditures for Customer Connections and New Load for each year 2021 through 2023.[10] The actual amounts are $184,832,000 for 2021, $214,093,000 for 2022, and $214,753,000 for 2023. After removing the net UMR expenditures discussed above for 2022 and 2023, the adjusted capital expenditures are $207,654,000 for 2022 and $206,652,000 for 2023.[11]

Using the above adjusted amounts for 2021-2023, I calculated an average annual spending level for the past three years of $199,713,000. In response to discovery, the Company also provided the number of customer connections installed by year from 2021 to 2023 and forecasted for 2024 and 2025. The data shows the number of customer connections declined from 21,280 in 2021 to 18,854 in 2022, and then a further decline to 17,555 in 2023. During the three-year period, the Company installed 19,230 customer connections on average, annually, at an average cost of $10,385 per installation.

For 2024 and 2025, the Company forecasted that the number of customer connections would increase by approximately 10% to 19,268, from 17,555 in 2023.[12] The forecasted number of connections for 2024 and 2025 do not reflect the current economic environment

[10] Exhibit AG-5 includes DR AGDE-3.95a and c with attachments.
[11] $214,093,000 - $6,439,000 = $207,654,000 for 2022; $214,753,000 - $8,101,000 = $206,652,000 for 2023.
[12] Id. includes DR AGDE-3.117.

of high interest rates that has dampened new construction. In response to discovery, the Company reported that the number of housing starts in Michigan is forecasted to decline by 3.8% in 2024 after declining by 6% in 2023. Housing starts in 2025 are forecasted to increase by 10.8% from the lower level in 2024. This is the best information we have to forecast customer connections for 2024 and 2025. Based on this information, I forecasted customer connections of 16,888 for 2024 and 18,712 for 2025.[13]

Using the $10,385 historical average cost per installation and adjusting it for inflation and then multiplying by the forecasted number of units, I calculated the forecasted capital expenditures for Customer Connections and New Load at $179,587,000 for 2024 and $203,362,000 for 2025.[14] In comparison, the Company forecasted capital expenditures of $194,040,000 for 2024 and $199,957,000 for 2025 after removing the UMR net capital expenditures.[15]

Therefore, I recommend that the Commission remove the difference of $14,453,000 from the Company's forecasted 2024 capital expenditures and increase the 2025 forecasted capital expenditures by $3,405,000.

Q. PLEASE DISCUSS THE ADJUSTMENTS YOU PROPOSE FOR UMR EXPENDITURES FOR 2024 AND 2025.

[13] 2024: 17,555 in 2023 x (1 – 3.8%) = 16,888. 2025: 16,888 x 1.108 = 18,712.
[14] 2024: $10,385 x 1.024 = $10,634 x 16,888 = $179,587,000. 2025: $10,634 x 1.022 = $10,868 x 18,712 = $203,362,000.
[15] 2024: 206,069,000 - $12,029,000 = $194,040,000. 2025: $218,608,000 – 18,651,000 = $199,957,000.

A. As discussed above, the Company forecasted Utility Make Ready capital expenditures, net of CIAC, of $12,029,000 for 2024 and $18,651,000 for 2025. These forecasted amounts are based on the premise that more customers, both residential and non-residential, will buy electric vehicles and will require modifications and additions to their electrical facilities to accommodate Level 2 and faster chargers. The forecasted net capital expenditures for 2024 and 2025 represent increases of 87% and 190% over 2022 actual net UMR expenditures, and 48% and 130% increases over the 2023 net UMR capital expenditures. These are very large increases in capital spending that are not reflective of the current market environment with EV sales.

During the first six months of 2024, EV manufacturers have realized that electric vehicles are not selling at the pace anticipated as late as 2023 and EVs are stockpiling at dealers' lots. EV buyers often have been dissatisfied with the actual driving range, particularly during the winter and hot days that quickly drain the car batteries. Reliability of certain vehicles with recalls for software and equipment failures has also created customer dissatisfaction and increased concerns and fear with prospective EV buyers. EV manufactures have cut back production of EVs, delayed new models, deferred building new batteries plants, and redirected resources to hybrid vehicles with batteries that self-charge during gasoline-fueled operation.[16] The current environment and demand for EVs

[16] Information gathered from recent articles in the Wall Street Journal, the Detroit News, and other publications.

does not support the increase in spending forecasted by the Company for 2024 and 2025 for UMR.

With EV adoption currently waning, I propose that the 2024 and 2025 capital expenditures for UMR be set at the 2023 amount plus inflation. It is best to be conservative during this time of uncertainty in EV purchases, to avoid having the Company earning on rate base additions plus recovering depreciation expense on costs that are not likely to materialize. If the Company actually spends more than I propose, it can recover those additional costs in the next rate case. This means forecasted net capital expenditures of $8,295,000 for 2024 and $8,478,000 for 2025 after CIAC.[17] In comparison, the Company forecasted net UMR expenditures of $12,029,000 for 2024 and $18,651,000 for 2025.

Therefore, I recommend that the Commission remove the difference of $3,734,000 for 2024 and $10,173,000 for 2025 from the Company's forecasted capital expenditures.

3. Relocations

Q. PLEASE PROVIDE YOUR ASSESSMENT OF FORECASTED CAPITAL EXPENDITURES FOR LINE RELOCATION PROJECTS.

A. On page 7 of Exhibit A-12, Schedule B5.4, the Company included forecasted capital expenditures for Relocations (Net of CIAC) of $45,618,000 for 2023, $50,480,000 for 2024. and $34,219,000 for 2025. Included in those amounts are capital expenditures for

[17] 2024: 2023 net UMR expenditures of $ 8,101,000 x 1.024 = $8,295,000. 2025: $8,295,000 x 1.022 = $8,478,000.

the I-375 relocation project of $5,938,000, $25,000,000, and $8,000,000 for 2023, 2024, and 2025, respectively. I will address this project separately from the more routine relocation projects. Excluding the I-375 project, the forecasted capital expenditures are $39,680,000 for 2023, $25,480,000 for 2024, and $26,210,000 for 2025. Based on the historical expenditures for routine relocations, I find the Company's forecasted amounts for 2024 and 2025 to be reasonable and I do not propose any adjustments.

Q. WHAT ADJUSTMENTS DO YOU PROPOSE FOR THE I-375 RELOCATION PROJECT?

A. On pages 25 and 26 of his direct testimony, Mr. Hill dedicates 8 lines of testimony to explain the I-375 relocation project with a total cost of $39 million. Mr. Hills states that the Company was notified by the Michigan Department of Transportation (MDOT) that the state plans to restructure the I-375 below-ground freeway into a grade level boulevard in 2025, which will require relocation of electrical lines. He also stated that work was to begin in 2023, with most of the work occurring in 2024 and finishing in 2025. As stated above, the Company forecasted capital expenditures of $5,938,000, $25,000,000, and $8,000,000 for 2023, 2024, and 2025, respectively.

In discovery, the Attorney General asked the Company to provide the timeline for each phase of the project and identify the phase the project was currently in. The discovery also requested that the Company provide the latest project schedule from MDOT showing the project start and completion dates. In response, the Company reported that the Relocation

phase of the project is currently in the engineering and design phase and work has begun to prepare contractor bid requests with construction currently planned for late 2024 and into the end of 2025. The second phase of the project for New Infrastructure installation has not begun and project scoping is planned for the fourth quarter of 2024 and conceptual analysis in the third quarter of 2025. The Company also reported that it has not received a project schedule from MDOT and has only received a notice to vacate.[18]

This last piece of information is very telling. It shows that MDOT has not set a firm schedule for the project. MDOT is known for establishing initial plans and later delaying projects. Although the Company may have done some design and engineering work in 2023 with the $5.9 million budgeted, it is unlikely that it will spend the $25 million forecasted for 2024 or the $8 million forecasted for 2025. It is premature and imprudent to include those large amounts in rate base in this rate case. The Company would be earning a return and recovering depreciation expense for costs that would likely not be incurred. Therefore, I recommend that the Commission remove the $25 million for 2024 and the $8 million for 2025 from the Company's forecasted capital expenditures.

4. Electric System Equipment

Q. PLEASE ASSESS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES FOR ELECTRIC SYSTEM EQUIPMENT.

[18] Exhibit AG-6 includes DR AGDE-3.91b and e.

A. On page 1 of Exhibit A-12, Schedule B5.4, the Company shows forecasted capital expenditures for Electric System Equipment of $33,655,000 for 2023, $33,300,000 for 2024, and $34,266,000 for 2025. According to Mr. Hill's direct testimony, the Company inflated the actual historical capital expenditures to arrive at its forecasted capital expenditures for the forecasted years. As discussed above, this approach is inappropriate as it unfairly increases costs to customers and should be rejected by the Commission.

In line with previously established practices approved by the Commission, I calculated the average capital expenditures for this capital program category for the three years 2021 to 2023 based on actual expenditures provided by the Company.[19] The Company spent $30,471,000 in 2021, $30,180,000 in 2022, and $27,670,000 in 2023 with an average annual amount of $29,440,000. After adjusting this amount for inflation, I calculated the 2024 forecasted capital expenditures at $30,147,000 and 2025 expenditures at $30,810,000.[20] These amounts are below the Company's forecasts by $3,153,000 for 2024 and $3,456,000 for 2025. I recommend that the Commission remove these amounts from the Company's forecasted capital expenditures.

5. General Plant, Tools, Equipment & Miscellaneous Items

Q. PLEASE ASSESS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES FOR GENERAL PLANT, TOOLS, EQUIPMENT & MISCELLANEOUS ITEMS.

[19] Exhibit AG-5 includes DR AGDE-3.95a with attachment.
[20] Three-year average amount x 1.024 for 2024 x 1.022 for 2025.

A. On page 1 of Exhibit A-12, Schedule B5.4, the Company shows forecasted capital expenditures for General Plant, Tools, Equipment & Miscellaneous Items of $5,866,000 for 2023, $9,144,000 for 2024, and $9,410,000 for 2025. According to Mr. Hill's direct testimony, the Company inflated the actual historical capital expenditures to arrive at its forecasted capital expenditures for the forecasted years. As discussed above, this approach is inappropriate, unfairly increases costs to customers, and should be rejected by the Commission.

In line with previously established practices approved by the Commission, I calculated the average capital expenditures for this capital program category for the three years 2021 to 2023 based on actual expenditures provided by the Company.[21] The Company spent $7,445,000 in 2021, $8,103,000 in 2022, and $6,090,000 in 2023 with an average annual amount of $7,213,000. After adjusting this amount for inflation, I calculated the 2024 forecasted capital expenditures at $7,386,000 and 2025 expenditures at $7,548,000.[22] These amounts are below the Company's forecasts by $1,758,000 for 2024 and $1,862,000 for 2025. I recommend that the Commission remove these amounts from the Company's forecasted capital expenditures.

[21] Exhibit AG-5 includes DR AGDE-3.95a with attachment.
[22] Three-year average amount x 1.024 for 2024 x 1.022 for 2025.

6. Portable Generators

Q. PLEASE ASSESS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES FOR PORTABLE GENERATORS.

A. On page 23 of his direct testimony, Mr. Hill briefly discusses the Company's plan to supply backup portable generators to certain customers during extended power outages. On line 28 of page 13 of Exhibit A-12, Schedule B5.4, the Company included $4.5 million of capital expenditures for the generators. In discovery, the Attorney General asked the Company to provide a few more pertinent details on this idea, such as the number of generators that would be purchased, who would qualify to receive them, how the generators would be connected to appliances, who would deliver and retrieve them, how they would be fueled, who would pay for the fuel, etc.

In response, the Company stated for anticipated power outages longer than 48 hours (2 days), the Company would identify a list of customers who would qualify to receive a portable generator with vulnerable customers prioritized. The Company's plan is to have available about 3,700 generators with 3,250 rated at 2200 Watt and 500 at 5000 Watt. The generators would be connected to certain appliances by an extension cord. No connections would be made to heating furnaces or air conditioners due to their hard-wired connections to circuit breakers and because the amperage requirements for air conditioners exceed the generator's capacity. The generators would be fueled with gasoline supplied by Company

employees or contractors. Non-field Company employees would deliver and retrieve the generators.[23]

Although the idea may seem appealing on the surface, it is fraught with pitfalls. The vulnerable customers that the Company aims to help need heat and air conditioning during periods of cold weather and hot days when the worst storms usually occur. The generators would not be able to help with either of those life-threatening needs. It is also not clear what those customers would do for the first two days until the generators are delivered. With tens of thousands of customers usually out of power for multiple days, the demand would overwhelm the small supply of generators, thus causing more customer ill will than appreciation. Gasoline delivery could be compromised if nearby gas stations also do not have power to operate their pumps.

If the Company believes there is merit and corporate image building benefits to such an idea, it should fund it with shareholder money. It is unfair for customers who pay the Company for electricity service, which they are not getting during power outages, to on top of that pay for backup generators through rates, which also may provide them with no service. I recommend that the Commission remove the $4.5 million from the Company's forecasted capital expenditures for 2024.

[23] DR AGDE-3.93a-f.

7. Tree Trimming Prioritization Model and Cost Savings

Q. PLEASE DISCUSS THE REDUCTIONS IN CAPITAL EXPENDITURES YOU PROPOSED RELATED TO THE TREE TRIMMING SURGE PROGRAM AND THE RISK PRIORITIZATION MODEL.

A. As discussed under the Working Capital section of my testimony, the Company proposed undertaking a Tree Trim Risk Prioritization Modeling approach, with also purchasing LiDAR technology, without first performing a cost/benefit analysis that demonstrated such a program would be economically justified. On page 17, line 24 of Exhibit A-12, Schedule B5.4, the Company included capital expenditures for this program of $3,078,000 in 2022 and $3,824,000 for 2023, for a total amount of $6,902,000. This capital spending is not justified and should be removed. I recommend that the Commission disallow the $6,902,000 from rate base in this rate case and also in future rate cases.

Additionally, in response to discovery, the Company reported that its tree trimming and surge program will achieve annual cost savings in capital spending of $66.9 million in 2024 and $59.6 million in 2025.[24] The Company did not include these capital spending savings in the capital expenditures exhibits or in rate base. The only reductions to capital expenditures that the Company reflected in the capital expenditures exhibits is on line 6 of page 1 of Exhibit A-12, Schedule B5.4 for Emergent Replacement Reductions from Strategic Spending and not from the tree trimming program. Therefore, I recommend that

[24] Exhibit AG-7 includes DR AGDE-4.167.

the Commission reduce the Company's forecasted capital expenditures for 2024 and 2025 by $66.9 million and $59.6 million, respectively.

In total for the tree trimming related programs, I recommend that the Commission remove $3,078,000 for 2022, $3,824,000 for 2023, $66,900,000 for 2024, and $59,600,000 for 2025. The O&M portion of the savings will be addressed in the Operations and Maintenance section of my testimony.

8. Electric Distribution 2023 Projects Underspent

Q. PLEASE DISCUSS THE AMOUNT OF FORECASTED 2023 CAPITAL EXPENDITURES IN THE DISTRIBUTION AREA THAT THE COMPANY UNDERSPENT.

A. In discovery, the Attorney General asked the Company to report on the actual amount of capital expenditures incurred in 2023 in the Electric Distribution area. The information provided in response to the discovery request shows that for 2023 the Company incurred actual capital expenditures for Base Capital Programs of $806,973,000.[25] In comparison, the Company forecasted $832,175,000 for the year. The difference of $25,202,000 should be removed from rate base in this rate case. The Company should not be earning a return or receive revenue to cover depreciation expense for costs that it did not incur.

[25] DR AGDE-3.95a with Attachment.

The Commission has previously ruled that underspent amounts included in projected rate base should be removed. Therefore, I recommend that the Commission continue that practice and remove the $25,202,000 from rate base in this rate case.

B. Power Generation- Fossil Fuel Plant Projects

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S PROJECTED CAPITAL EXPENDITURES FOR POWER GENERATION FACILITIES.

A. On page 3 of Exhibit A-12, Schedule B5.1, the Company forecasted Routine capital expenditures in the Power Generation area of $274 million for 2023, $273.8 million for 2024, and $192.4 million for 2025. In my review of the proposed expenditures, I identified two adjustments, which I discuss below.

1. Greenwood and Belle River Plants

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU PROPOSE FOR THE GREENWOOD AND BELLE RIVER PLANTS.

A. In response to discovery, the Company provided the actual routine capital expenditures by plant site for each year 2021 to 2023. The information provided shows that for the Greenwood plant, capital expenditures averaged $9,992,000 during this three-year

period.[26] For the five-year period from 2019 to 2023, the average spending amount is even less at $9,436,000. In comparison, for 2024 and 2025, capital expenditures were forecasted by the Company to nearly double to $18,817,000 and $18,680,000, respectively. Routine capital expenditures are typically consistent and repetitive. The direct testimony and exhibits sponsored by Company witness Margaret Guillaumin identify certain projects that the Company plans for 2024 and 2025 but there is insufficient justification why the number of projects and amount of forecasted capital expenditures needs to double after only a year, from the actual spending level in 2023.

To develop a reasonable forecast, I applied the rate of inflation for 2024 and 2025 to the average amount of $9,992,000 spent during the most recent three years, to arrive at the 2024 forecast of $10,232,000 and $10,457,000 for 2025. These amounts are lower than the Company's forecasted amount of $18,817,000 for 2024 and $18,680,000 for 2025. The difference is $8,585,000 in 2024 and $8,223,000 for 2025. I recommend that the Commission remove these amounts from the Company's forecasted capital expenditures.

Similarly, for the Belle River plant, the three-year average capital spending during 2021 to 2023 was $44,609,000. After applying inflation to this amount, I calculated 2024 capital expenditures of $45,680,000 for 2024 and $46,685,000 for 2025. The Company forecasted capital expenditures of $58,950,000 for 2024 and $42,757,000 for 2025. The reduction in spending in 2025 appears reasonable. However, the large difference in spending of

[26] Exhibit AG-8 includes DR AGDE-3.111 with attachment.

$13,270,000 for 2024 is not reasonable or justified and the Commission should remove it from the Company's forecasted capital expenditures.

2. Power Generation 2023 Projects Underspent

Q. PLEASE DISCUSS THE AMOUNT OF FORECASTED 2023 CAPITAL EXPENDITURES IN THE FOSSIL GENERATION AREA THAT THE COMPANY UNDERSPENT.

A. In discovery, the Attorney General asked the Company to report on the actual amount of capital expenditures incurred in 2023 in the Power Generation area. The information provided in response to the discovery request shows that for 2023 the Company incurred actual capital expenditures of $450,247,000.[27] In comparison, the Company had forecasted $454,198,000 for the year. The difference of $3,951,000, which should be removed from rate base in this rate case. The Company should not be earning a return or receive revenue to recover depreciation expense for costs that it did not incur.

C. Nuclear Generation- Capital Projects

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES IN THE NUCLEAR POWER GENERATION AREA.

[27] Id. includes DR AGDE-3.107 with attachment.

A. On page 1 of Exhibit A-12, Schedule B5.3, the Company forecasted capital expenditures in the Nuclear Generation area of $266.7 million for 2023, $184.8 million for 2024, and $215.9 million for 2025. The capital expenditures include both routine and non-routine projects, plus the cost of nuclear fuel. In my review of the proposed expenditures, I identified several adjustments, which I discuss below.

1. Security System Computer

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU PROPOSE FOR THE SECURITY SYSTEM COMPUTER PROJECT.

A. On line 4 of page 2 of Exhibit A-12, Schedule B5.3, the Company shows capital expenditures for the security computer system of $7,080,000 in 2022, $17,610,000 for 2023, and $9,197,000 for 2024 for a total amount of $33,887,000 over the three-year period.

To assess the reasonableness and prudency of the capital spending for this project, in discovery the Attorney general asked the Company to provide the initial estimated cost of the project with the implementation timeline, the current forecasted cost of the project from inception to completion by year, the current implementation timeline, and explanations of project cost variances of 10% or greater, along with bid information from outside contractors and equipment vendors.

In response the Company provided two Appropriation Request documents with approval dates of January 26, 2023 and June 26, 2024. The documents show that the initial amount requested for project approval was $9,948,000, and that amount was increased to $25,174,000 on January 26, 2023, with a project in-service date of December 29, 2023. No explanation was provided as to why the project cost increased by more than $15 million. The Appropriation Request document includes a description stating that this additional amount would be spent on engineering, system vendor design, fabrication, and some installations and upgrades.

The second document shows an additional increase in cost of $14 million for a new total project cost of $39,173,000, with an in-service date of December 29, 2024. The description provided on the document repeats the explanation from the previous month and adds a list of additional equipment and functions.[28] However, it provides no clear explanation why these additional tasks and requirements were being added in June 2024, three years after the project start date of May 2021. The Company's responses to the discovery questions discuss only project cost changes from rate case to rate case in broad and general terms without providing insight into the total current cost of the project versus the initial approval amount, as was requested.

The initial project cost of $9,948,000 has now mushroomed to $39,173,000, for an increase of $29,225,000. This increase is an excessive cost overrun and reflects an imprudent and

[28] Exhibit AG-9 CONF includes DR AGDE-3.98a-d with the Appropriation Request documents.

unreasonable approach to project cost management. Although some cost increases can be expected with certain projects from time to time due to unexpected problems that may occur, a reasonable expectation for cost increases should not exceed 10% of the project cost. Applying that percentage to the original project cost of $9,948,000 results in a maximum project cost of $10,943,000. The $39,173,000 total cost of the project exceeds that amount by $28,230,000. It would be unfair and unreasonable to burden customers with that excess cost. Therefore, I recommend that the Commission remove that amount from this rate case, with $9,197,000 removed from the Company's forecasted 2024 capital expenditures and the remainder of $19,033,000 from 2023 and prior years.

2. Plant Radio System

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU PROPOSE FOR THE PLANT RADIO SYSTEM REPLACEMENT PROJECT.

A. On line 5 of page 2 of Exhibit A-12, Schedule B5.3, the Company shows capital expenditures for the radio system replacement project of $4,176,000 in 2022, $6,050,000 for 2023, and $1,498,000 for 2024, for a total amount of $11,724,000 over the three-year period.

To assess the reasonableness and prudency of the capital spending for this project, the Attorney General asked the Company to provide the initial estimated cost of the project with the implementation timeline, the current forecasted cost of the project from inception to completion by year, the current implementation timeline, and explanations of project

cost variances of 10% or greater, along with bid information from outside contractors and equipment vendors.

In response the Company provided two Appropriation Request documents. The first document has an approval date of October 28, 2022 and the second document has no approval or preparation date. The documents show that the initial amount requested for project approval was $6,000,000, with that amount increasing to $15,815,000 on October 28, 2022, with a project in-service date of December 31, 2023. No explanation was provided for why the project cost increased by more than $9.8 million, other than a description that this additional amount would align with the "8+4 2022 forecast."

The second document shows an additional increase in cost of $3,615,000, for a new total project cost of $19,430,000, with an in-service date of December 31, 2024. The description provided on the document states that the additional costs were incurred due to delays caused by plant conditions that impacted personnel availability and discovery of legacy issues with undersized wiring.[29] As I pointed out above, no approval for this additional spending is shown on the Appropriation Request document. From the document it is not clear why the legacy issues were discovered this late in the process, which is at least three years after the project start date of January 2019, or why availability of plant personnel was an issue that would increase project costs. The Company's responses to the discovery questions discuss only project cost changes from rate case to rate case in broad

[29] Exhibit AG-10 CONF includes DR AGDE-3.99a-d with the Appropriation Request documents.

and general terms, without providing insight into the total cost of the project now versus the initial approval amount, as requested.

What we know is that the initial project cost of $6,000,000 has now increased by $13,430,000, to $19,430,000. This increase is another excessive cost overrun and reflects an imprudent and unreasonable approach to project cost management. Although some cost increases can be expected due to unforeseen problems that may occur in the implementation phase of the project, a reasonable expectation for cost increases should not exceed 10% of the project cost. Applying that percentage to the original project cost of $6,000,000 results in a maximum project cost of $6,600,000. The $19,430,000 total cost of the project exceeds that amount by $12,830,000. It would be unfair and unreasonable to burden customers with that excess cost. Therefore, I recommend that the Commission remove that amount from this rate case, with $1,498,000 removed from the Company's forecasted 2024 capital expenditures and the remaining amount of $11,332,000 from 2023 and prior years.

3. Nuclear Fuel

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU PROPOSE FOR NUCLEAR FUEL COSTS.

A. On lines 5 through 10 of page 1 of Exhibit A-12, Schedule B5.3, the Company shows capital expenditures for nuclear fuel of $135,077,000 for 2025. This amount exceeds the cost of nuclear fuel of $110,008,000 in 2023 from the Company's previous refueling

session by approximately $15 million. In discovery, the Attorney General asked the Company to explain how the fuel costs for the 2025 projected test year were determined and why they increased significantly from 2023. The Company was also asked to provide the historical fuel costs incurred annually from 2018 to 2023.

In the response, the Company discusses variances in the number of fuel assemblies from outage to outage without addressing specifically the cost variance between 2023 and 2025, and states the calculation is in accordance with industry accepted software and rules, without providing further explanation or support for the calculation.[30] The bottom line is that the cost increase is not adequately explain or supported.

Based on the historical information provided by the Company, nuclear fuel costs were $120,112,000 in 2021 and $110,008,000 in 2023.[31] The average cost for the two years is $115,060,000. The $135 million forecasted for 2025 is $20 million more than the amount spent on average over the last two refueling periods.

It is also noteworthy to point out that in Case No. U-20836, the Company forecasted that it would spend $122,703,000 for nuclear fuel in 2021 but actually spent $120,112,000. For 2023, the Company forecasted $117,421,000 for 11 months of costs for nuclear fuel, which annualized means it had forecasted $128,100,000 for the entire year. The actual amount for 2023 was $110,008,000, or $7.4 million lower than the 11 months forecast and

[30] Exhibit AG-11 includes DR AGDE-3.102b.
[31] Id. includes DR AGDE-3.102a with attachment.

$18 million lower than the full 12 months forecasted for the year. This historical perspective shows that the Company has a propensity to overestimate the cost of nuclear fuel.

The 2025 nuclear fuel cost is out of line with historical levels by a least $20,017,000. Therefore, I recommend that the Commission remove this amount from the Company's forecasted capital expenditures for 2025.

4. Nuclear Capital Projects

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU PROPOSE FOR VARIOUS LARGE NUCLEAR PLANT PROJECTS.

A. On pages 3 and 4 of Exhibit A-12, Schedule B5.3, the Company listed several projects with related capital expenditures and provided the in-service dates. For projects in size of $3 million and greater, the Attorney General requested the Company to provide additional information for each project, why it was necessary, and to provide the project phases with a timeline and the current phase of the project along with other relevant information.

In response, the Company referenced information previously provided in Attachment 9 to the Part III Supplemental filing and to discovery responses submitted to other parties. However, the information requested was not in the referenced Part III documents or in the other discovery responses. In the response, the Company also stated that the Nuclear Generation department does not categorize projects in phases of development and simply

dismissed the request.[32] The response is at odds with common project management practices. Projects typically have phases of development that start with project concept and scoping of project needs, followed by engineering design, project bidding to contractors, construction, and completion. In this case, either the Nuclear department is reluctant to disclose that information or is following an unorthodox project management approach. In either case, the Company's response does not inspire confidence that some of the larger projects listed on pages 3 and 4 of Schedule B5.3 are eligible for inclusion in rate base in this rate case.

Specifically, for the three projects on lines 59, 60, and 61 of page 3 of Schedule B5.3: Natural Draft Cooling Towers, Document Management System Enhancements, and Remote Monitoring, the Company should have identified project phases and timelines with a completion in-service date. The Company has failed to do so and the forecasted capital expenditures remain unsupported. These projects have total capital expenditures of $23,980,000 for 2025. The Company has not made an adequate effort to justify these projects for inclusion in rate base in this rate case. Therefore, I recommend that the Commission remove the total capital expenditures amount of $23,980,000 from the Company's forecasted capital expenditures.

Similarly, on page 4 of Schedule B5.3, the Company shows 4 projects with an in-service date of 2026. These projects are on lines 1, 10, 16, and 26. The projects will not be

[32] Exhibit AG-12 includes DR AGDE-3.103a and b.

completed before the end of the projected test year and will not be used and useful in 2025. Therefore, the total amount of capital expenditures for 2024 of $58,039,000, and $25,874,000 for 2025, should be removed from this rate case. The project on line 28 for the Sanitary System Replacement should have a project plan and timeline with a stated completion date and in-service date. The "Annual" in-service date designation by the Company would imply an annual program, which does not appear to be correct for this project. The Company's inability or unwillingness to provide a project timeline and current phase of development makes it impossible to accept the 2025 capital expenditures of $6,457,000 for inclusion in rate base in this rate case.

Therefore, in total, I recommend that the Commission remove capital expenditures of $58,039,000 for 2024 and $56,311,000 for 2025 from the Company's forecasted capital expenditures.

D. Information Technology Projects

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL EXPENDITURES FOR INFORMATION TECHNOLOGY (IT) PROJECTS PROPOSED BY THE COMPANY.

A. Both Company witnesses Michael Hatsios and Pankaj Sharma propose capital expenditures for IT projects. Mr. Hatsios focuses on Customer Service-related projects and Mr. Sharma on other IT projects. I will discuss cost disallowances pertaining to projects proposed by each witness.

With regard to the Customer Service IT projects of $3 million and greater included in Exhibit A-12, Schedule B5.7.3, the Attorney General asked the Company in discovery to provide a project description, statement of necessity, and a project development timeline with the current phase of the project identified among other pertinent information. In response, the Company identified certain projects with capital expenditures included in 2024 and 2025 where no work has yet been started or the project is in the early phase of development. This is the case for the four projects on lines 4, 11, 15, and 18 of Schedule B5.7.3.

The four projects are (1) the MIGP Customer Requested Renewable Energy Project, which will not kick-off until August 2024; (2) the MIGP Scope Billing and Enrollment project, which will not be completed until 2026; (3) the Rider 17-MIGreenPower Residential and Commercial projects, which are still in the early design phase or will not kick-off until 2025; and (4) the 2025 Advance Analytics Use Cases for Reducing MPSC Complaints, which will not start until March 2025.[33] The total capital expenditures for the four projects are $5,750,000 for 2024 and $15,393,000 for 2025.

Given that these projects have not yet started the initial scoping phase, are in the early phase of development, or will not be completed by the end of the projected test year, it is premature to include the forecasted capital expenditures in rate base. Therefore, I

[33] Exhibit AG-13 includes DR AGDE-3.114a-d.

recommend that the Commission remove the $5,750,000 and the $15,393,000 from the Company's forecasted capital expenditures for 2024 and 2025, respectively.

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL EXPENDITURES FOR IT PROJECTS SPONSORED BY MR. SHARMA.

A. In discovery, the Attorney General made the same request of the IT projects sponsored by Mr. Sharma in Exhibit A-12, Schedule B5.7.1, as described above for Customer Service projects of $3 million and greater. The request was for the Company to provide a project description, statement of necessity, and a project development timeline with the current phase of the project identified, among other pertinent information.

In response, the Company provided references to pages of Mr. Sharma's testimony for project descriptions and necessity with a further reference to the project charter in Exhibit A-24, Schedule N1. Although the referenced sources provide some of the requested information, they do not provide all the requested information. More concerning is the Company's dismissal of the request to provide the project phases with related timeline and the current phase of the project. Instead, the response to DR AGDE-3.123b provides what appear to be generic weekly and monthly project deadlines.[34] This is not the information requested and it is dissimilar to the information provided by the Company for Customer

[34] Exhibit AG-14 includes DR AGDE-3.123a-d.

Service IT projects discussed above and shown on pages 2 and 3 of DR AGDE-3.114b (Exhibit AG-13).

In Schedule B5.7.1, there are two projects with capital expenditures in excess of $3 million. The first project is on line 9 for Cloud Health and Safety, with capital expenditures of $2,518,000 in 2024 and $582,000 in 2025. The second project is on line 16 for Enhanced Document Management Capability Projects, with capital expenditures of $1,218,000 in 2024 and $2,958,000 in 2025. Given the lack of information, it is not possible to determine what phase those projects are currently in or whether they will be completed by the end of the projected test year and be used and useful.

Therefore, I recommend that the Commission remove the $1,218,000 for 2024 and $2,958,000 for 2025 from the Company's forecasted capital expenditures.

Q. PLEASE DISCUSS THE AMOUNT OF FORECASTED 2023 IT CAPITAL EXPENDITURES THAT THE COMPANY UNDERSPENT.

A. In discovery, the Attorney General asked the Company to provide the actual amount of capital expenditures incurred in 2023 in the Information Technology area. The information provided in response to the discovery request shows that for 2023 the Company incurred actual capital expenditures of $127,456,000.[35] In comparison, the Company had forecasted $162,310,000 for the year in Exhibit A-12, Schedule B5.7. The

[35] Exhibit AG-15 includes DR AGDE-3.122 with attachment.

difference of $34,854,000 should be removed from rate base in this rate case. The Company should not be earning a return or receive revenue to recover depreciation expense for costs that it did not incur.

E. Corporate Capital Projects

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL EXPENDITURES IN THE CORPORATE AND VEHICLE TRANSPORTATION AREAS.

A. In Exhibit A-12, Schedule B5.8, the Company shows forecasted capital expenditures for corporate functions of $138.9 million for 2023, $97.0 million for 2024, and $120.1 million for 2025. Company witness Theresa Uzenski discusses the corporate capital expenditures in her direct testimony. Pages 2 and 3 of Schedule B5.8 provide a list of major projects with the related capital expenditures for 2022 through 2025.

On pages 61 and 62 of her direct testimony, Ms. Uzenski states that certain renovations and updates were necessary at the Company's downtown campus due to employees returning to work for a mandatory minimum 3 days per week, and to build conference and huddle rooms in the lobby of the Cisler building, for a total cost of $14,265,000 between 2023 and 2024.[36] In discovery, the Attorney General asked the Company to explain why employees are required to report to their office location for three days a week versus the

[36] Exhibit A-12, Schedule B5.8 page 2, lines 27-32.

whole week, what efficiencies are gained from the 3-day requirement, and why office space from pre-Covid that accommodated employees for a full week is now not sufficient and needs to be renovated. In response, the Company had no clear answers to the questions, pointing simply to company policy decisions and the need for developing agile work space and reconfiguring office furniture.[37]

Additionally, the AG asked the Company to explain why it was spending capital on new furniture, additional huddle rooms, conference rooms, monitors, work stations, video conferencing and on other items, when those facilities and equipment were previously used by the same employees who worked at the same office location for a full week versus only three days a week now. The responses that employees need equipment both at home and at the office is not persuasive and shows an inclination to increase capital spending to accommodate situations that are not most efficient. It is also perplexing why the Company would need additional video conferencing capabilities four years after the outbreak of Covid-19, which initially increased the use of video conferencing.

The conversion of open space in the lobby of the Cisler building into conference and huddle rooms at a cost of $4.8 million is another example of wasteful spending. For the occasional use that these conference and huddle rooms will have when required by larger

[37] Exhibit AG-16 includes DR AGDE-3.127a-d.

groups, it does not justify the significant cost. Those large groups could gather at other locations that previously accommodated them.[38]

The renovations undertaken at the Company's headquarters building are not a wise use of capital that could be used instead to improve the distribution grid for increased reliability. The expenditures are not prudent and reasonable. Therefore, I recommend that the Commission remove $6,265,000 for 2023 and $8,000,000 for 2024 from the capital expenditures forecasted by the Company.

Q. ARE THERE OTHER CAPITAL EXPENDITURES FOR PROJECTS IN THE CORPORATE AREA THAT NEED TO BE ADJUSTED?

A. Yes. For projects of $3 million or greater, the Attorney General asked the Company to provide a project description, statement of necessity, and a project development timeline with the current phase of the project identified among other pertinent information. In response, the Company identified certain projects with capital expenditures included in 2024 and 2025 where the project is still in the initial concept phase or will not be completed until after the end of the 2025 projected test year.[39]

The information provided by the Company shows 8 projects in the Initial Concept phase with total capital expenditures of $17,600,000. These projects are on lines 22, 24, and 25 of page 2 and lines 8, 9, and 12 of page 3 of Schedule B5.8. The same line number

[38] Id. includes DR ADGDE-3.127e.
[39] Id. includes DR AGDE-3.131a-c with attachments.

correspond to the attachment to DR AGDE-3.131b&c in Exhibit AG-16. These projects are still in the early stage of development and premature to include in rate base. The timing and cost can change significantly before project specifications, design, and work begins on those projects. Customers should not run the risk of paying in rates for costs that the Company may not incur.

Additionally, the Training and Development Center Renovation on line 23 of page 3 of Schedule B5.8 has an in-service date of 2026. This project with forecasted capital expenditures of $7.0 million in 2025 will not be used and useful in 2025 and the capital expenditures should be removed from rate base in this rate case.

Therefore, in total, for the 9 projects, I recommend that the Commission remove $24,600,000 from the Company's forecasted capital expenditures for 2025.

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO CAPITAL EXPENDITURES FOR VEHICLES AND EQUIPMENT SUPPORTING THE ELECTRICAL OPERATIONS?

A. Yes. On line 1 of Exhibit A-12, Schedule B5.8, the Company shows the capital spending for vehicle fleet supporting the electric operations with forecasted capital expenditures of $32,791,000 for 2023, $38,236,000 for 2024, and $42,600,000 for 2025. In discovery, the Attorney General asked the Company to provide the number of vehicles purchased of each type or class for years 2021 to 2023 and forecasted for 2024 and 2025, with the related dollars.

In response, the Company referenced discovery responses provided to Staff. The information provided to Staff pertains to only 2023 and 2024 and does conform to the request made by the Attorney General.[40] Given this lack of information, a reasonable approach to forecast capital expenditures in this area is to use the average capital spending during the most recent three years and adjust that amount for forecasted inflation in 2024 and 2025.

Based on information provided by the Company, the average amount spent on the transportation fleet was $32,883,000 during the three years 2021 to 2023.[41] Adjusted for inflation, the forecasted capital expenditures are $33,622,000 for 2024 and $34,413,000 for 2025. These amounts are lower than the Company's forecast by $4,564,000 for 2024 and $8,187,000 for 2025. I recommend that the Commission remove those amounts from the Company's forecasted capital expenditures.

F. EV Charging Forward Program

Q. WHAT ADJUSTMENTS TO CAPITAL EXPENDITURES FOR THE EV CHARGING FORWARD PROGRAM DO YOU PROPOSE?

A. In Exhibit A-12, Schedule B5.9, the Company shows a major escalation in capital expenditures in 2024, with $12.5 million of forecasted spending from less than $1.0 million in 2023. Forecasted capital expenditures decline to $5.1 million in 2025. This increase in

[40] AG-17 includes DR AGDE-3.130bii.
[41] Id. includes DR AGDE-3.130a with attachment.

spending presumes an increased interest by businesses for installation of charging infrastructure with very large subsidies paid to those businesses to install chargers and batteries. As stated above in my testimony under the Utility Make Ready capital expenditures, the general interest in electric vehicles is currently waning and throwing more money at the program than demand warrants at this time is not a prudent move.

Therefore, consistent with my recommendations in the Utility Make Ready testimony, I propose that the forecasted capital expenditures in Schedule B5.9 be reduced by 45% for 2024 and 2025.[42] This means a reduction in capital expenditures of $6,979,000 for 2024 and $2,295,000 for 2025. The lower amounts included in rate base will protect customers from the Company's potential underspending on the program. However, if the Company were to exceed those amounts, it can request recovery for the additional amount in the next rate case.

G. Capital Expenditures Adjustments - Summary

Q. WHAT IS THE TOTAL AMOUNT OF ADJUSTMENTS THAT YOU RECOMMEND 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,

[42] Make Ready reductions of $13.9 million from Company's forecasted net UMR of $30.68 million for 2024 and 2025 = 45%.

unnecessary, or unsupported. It also includes capital cost disallowances proposed by other witnesses presenting testimony on behalf of the Attorney General.

Summary of AG Disallowed Capital Expenditures		
		Amount (millions)
Distribution Operations	$	688
Power Generation		34
Nuclear Operations		175
Customer Service/IT		60
Corproate Facilities		52
EV Program		9
Total	$	1,018

Based on my analysis and the information presented in my testimony above, the Commission should reduce the Company's proposed capital expenditures by $1,018 million and average rate base by $783.9 million, including an adjustment of $25.7 million to 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 $1.295 BILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY'S FORECASTED AMOUNT?

A. No. I propose three adjustments, which reduce the level of Working Capital for the project by $25.7 million. The first adjustment is to eliminate the Company's regulatory asset of

$9.9 million related to its Ludington power generating facility shown on line 27 of Exhibit A-12, Schedule B4. The second adjustment pertains to the Company's regulatory asset for the Incentive Compensation Deferral shown in Exhibit A-12, Schedule B4. This item is shown on line 41 of the exhibit as a $3.9 million asset. Instead, as explained below, a $6.1 million average liability (not an asset) should be established in the Working Capital projection. This reduces the average Working Capital balance by $10.0 million.

The third adjustment pertains to the regulatory assets for the deferral of costs for the Time of Day (TOD) implementation program. The adjustment amount reduces Working Capital by $5.8 million, as discussed in more detail below.

Q. PLEASE EXPLAIN THE REMOVAL OF THE $9.9 MILLION REGULATORY ASSET FROM WORKING CAPITAL RELATED TO THE COMPANY'S JOINTLY OWNED LUDINGTON PUMPED STORAGE FACILITY.

A. Based on a Commission order in Case No. U-21310, the Company has been deferring certain costs and the estimated liquidated damages pertaining to defective work by Toshiba at the Ludington power generating facility. The net amount of the costs and liquidated damages deferred by the Company and included in a regulatory asset by the Company is $9,933,000. In response to discovery, the Company provided the components of these costs and liquidated damages and stated that the deferred amount represents the balance as of December 3, 2023.[43] The costs pertaining to the power outages, liquidated damages,

[43] Exhibit AG-19 includes DR AGDE-1.20a and b.

and other costs pertaining to Toshiba work problems at the Ludington plant have been a matter of litigation in several Power Supply Cost Recovery cases. The Attorney General and other parties to the proceedings have taken different positions than the Company on whether DTEE should be responsible to absorb the cost of replacement power from multiple and extended power outages at the plant and how liquidated damages should be apportioned to offset replacement power costs and other costs incurred by the Company.

The unsettled dispute and uncertainty as to how much the Company will eventually be allowed to recover of the net deferred costs makes it imperative that the Company should not earn a return on the deferred amount until the Commission rules on the appropriate amount to be recovered in rates. Therefore, I recommend that the Commission remove the $9,933,000 from Working Capital in this rate case. Once the Commission decides the appropriate amount of deferred costs that the Company should be allowed to recover, if any, the appropriate return can be calculated and included with the deferred amount for the period of time that the recoverable portions of the net costs were outstanding.

Q. PLEASE EXPLAIN THE INCENTIVE COMPENSATION DEFERRAL AND HOW THE COMPANY ARRIVED AT ITS DEFERRED BALANCE OF $3.9 MILLION.

In Case No. U-20836, the Commission approved recovery of only 60% of the Company's proposed incentive compensation related to operating performance measures for the projected test year ending October 2023. In addition, the Commission directed the

Company to establish a two-way cost tracking mechanism for incentive compensation earned in the projected test year based on the actual performance level achieved relative to the performance level in the incentive compensation amounts included in rates. The pertinent section of the Commission's November 18, 2022 Order states:

> For operational metrics, the Commission finds the Attorney General's arguments persuasive that DTE Electric should recover costs for operational metrics achieved at target or better over the past five years. The Commission adopts this approach consistent with its December 9 order in DTE Gas's last general rate case, Case No. U-20940. The Commission adopts the Attorney General's 40% disallowance and permits DTE Electric to recover 60% of its proposed incentive compensation expense for operational metrics. The Commission adopts the Attorney General's proposed disallowance of 40% of $21,225,000 for a total EICP expense of $12,735,000. In addition, the Commission authorizes DTE Gas to implement a two-way tracker mechanism, which will require refunds to customers if the 60% target level is not achieved or will allow the company to recover additional funds if it exceeds the 60% target level, up to a maximum of 100% target level.

From reviewing the calculations in Exhibit A-13, Schedule C5.10.1, it is apparent that the Company did not properly follow the methodology that the Commission approved in Case No. U-20836 in determining the amount of incentive compensation that it actually earned during 2023. In filed exhibits, the Company did not show how it arrived at its actual compensation amount of $5,987,000 for 2023. This amount is slightly higher than the $5,943,000 that I calculated in Exhibit AG-20, as discussed in more detail below.

In addition, the Company included in the regulatory asset an accrual of $9.8 million for 2024 incentive compensation that it has not earned yet, on the assumption that it would achieve 100% of its operating incentive metrics for 2024. This is not only premature but

inconsistent with historical performance. As shown later, the Company only achieved 28% of its operating metrics in 2023 at target level or better.

The Company also included an additional accrual for 2022 of $856,000. Although the Company did not discuss this amount in filed testimony or explain it in the exhibit, it is assumed that it is trying to recover the amount of compensation for 43 days from the date of the order in Case No. U-20836 on November 18, 2022 to December 31, 2022. No calculations were provided in filed exhibits to support this amount. However, this amount should be easily dismissed. The Company achieved actual performance on the operating metrics of only 52% at target level or better in 2022. For the projected test year, in Case No. U-20836, the Company received recovery of incentive compensation for operating metrics at 60%. The 52% achieved in 2022 is less than the 60% included in rates, Therefore, if any adjustment should be made for the 43 days in 2022, it would be to reduce the amount recovered in rates and an additional refund to customers. As shown in my calculations in Exhibit AG-20, I exclude any amount pertaining to 2022, concluding that it was de minimis.

The Company's calculation of the regulatory asset for the incentive compensation deferral is inappropriate and the Commission should reject it.

Q. HAVE YOU DETERMINED WHAT THE APPROPRIATE REGULATORY ASSET/LIABILITY BALANCE AND AMORTIZATION EXPENSE FOR 2023 SHOULD BE FOR THE DEFERRED INCENTIVE COMPENSATION AMOUNT?

A. Yes. In Exhibit AG-20, I applied the percentage of actual performance achieved for the operational performance measures in each of the two incentive plans in 2023 to the amount of incentive payout of $21,225,000 at 100% of target that Company witness Michael Cooper forecasted for operating metrics on page 53 of his direct testimony in Case No. U-20836. The $21,225,000 is the base amount on which the Commission approved the 60% recovery amount of $12,735,000 in base rates and should be the same amount on which to calculate the final incentive compensation amount applying the actual performance measures achieved in 2023.

This calculation results in an actual performance incentive amount of $5,943,000 for 2023. When compared to the $12,735,000 included in rates in Case No. U-20836, the difference is an over-recovery of $6,792,000, which is owed by the Company to its customers. Lines 1 through 7 of Exhibit AG-20 show the calculations. The over-recovery results in a regulatory liability of $6,792,000 as of the beginning of the 2025 projected test year, in contrast with the Company's improperly established regulatory asset of $3,884,000.

I propose that the negative balance of $6,792,000 in the regulatory liability be amortized over a five-year period and the annual amortization expense, which is a credit of $1,358,000 in this case, be reflected in O&M expense and in rates beginning with this rate case. I chose a five-year amortization period because it is sufficiently long to smooth out future changes to the regulatory asset as positive or negative accruals are recorded to the account and to minimize volatility to the amortization expense from rate case to rate case. The Company did not propose an amortization expense in this rate case.

The $6,792,000 in regulatory liability I calculated in comparison to the Company regulatory asset of $3,884,000 results in an adjustment of $9,997,000 to working capital, as shown in Exhibit AG-20. Therefore, I recommend that the Commission remove the $9,967,000 from the Company's forecasted working capital balance amount for the projected test year and include the $1,358,000 of negative amortization as a reduction to the Company's forecasted O&M expenses for the projected test year in this rate case.

Q. ON PAGE 86 OF HER TESTIMONY, MS. UZENSKI RECOMMENDS CERTAIN MODIFICATIONS TO THE INCENTIVE COMPENSATION TRACKER MECHANISM. DO YOU AGREE?

A. No. On page 86 of her direct testimony, Ms. Uzenski proposes three modifications. The first modification pertains to setting a new base amount of approved compensation to use for future deferrals. This proposal is appropriate and should be adopted if the Commission decides to continue the mechanism. The second proposal is to also include incentive compensation related to financial measures. This proposal should be rejected. The Commission has repeatedly made it clear that inclusion in rates of incentive compensation related to financial measures is inappropriate and no convincing evidence has been provided in this rate case that the Commission should change its prior decisions.

The third proposal is to include compensation payout above 100% of target. This proposal also should be rejected. As I have stated in my testimony below in the Incentive Compensation section, several of the operating performance measures have a very low

threshold to achieve payout under the plan and it is relatively easy for the Company to exceed the 100% target level without achieving superior performance. The deferral mechanism should not bypass what the Commission has previously accepted as reasonable recovery of incentive compensation capped at 100% of target.

In summary, the Commission should reject the second and third proposed modifications to the mechanism.

Q. PLEASE DISCUSS YOUR ADJUSTMENT TO THE TOD IMPLEMENTATION PROGRAM.

A. On line 27 of Exhibit A-12, Schedule B4, the Company proposed a working capital amount of $5,784,000 for the TOD program. This program was implemented beginning in 2022 to allow the Company to inform and prepare customers for significant changes to customer rate tariffs that would be implemented in 2023. The Company received approval to defer the applicable costs for future review and recovery if deemed prudent and reasonable. In this rate case, the Company filed Exhibit A-13, Schedule C5.9.2, showing that it had incurred net costs of $1,979,000 in 2022 and forecasted additional costs of $6,486,000 for 2023. Included in the 2023 forecasted amount were customer service costs of $5,152,000 for the addition of customer service representatives to handle anticipated additional telephone calls and other related inquiries due to the TOD rate tariff changes.

In neither filed testimony nor in its exhibits, did the Company provide any evidence that the costs incurred in 2022 and forecasted for 2023 were reasonable and prudent. In

discovery, the Attorney General asked the Company to provide the specific costs it incurred for items of $100,000 or greater in order to perform a reasonableness and prudency review. In response, the Company provided summary statements about the major categories of costs it incurred for 2022 and forecasted for 2023, with no itemized list of actual costs or calculations as to how it arrived at the forecasted costs.[44] The information provided is inadequate to establish the reasonableness and prudency of the amounts included in the regulatory assets and partially amortized to expense in this rate case.

The Company included $6,486,000 of forecasted costs for 2023 in determining the regulatory asset and amortization expense, thus attempting to earn a return and recover forecasted costs that cannot be validated for reasonableness and prudency. By removing the forecasted costs for 2023 from the regulatory asset, the working capital balance for the projected test year is reduced to zero and so is the amortization expense of $1,693,000 calculated in Exhibit A-13, Schedule C5.9.3.

Therefore, I recommend that the Commission remove the $5,784,000 of working capital for the TOD program and the $1,693,000 of amortization expense from the Company's forecasted amounts for the projected test year.

[44] Exhibit AG-22 includes DR AGDE-4.156a with attachment.

Q. PLEASE SUMMARIZE THE TOTAL AMOUNT OF ADJUSTMENTS YOU PROPOSE FOR THE PROJECTED TEST YEAR.

A. The three adjustments discussed above total to $25,684,000. I recommend that the Commission reduce the Company's forecasted Working Capital amount for the projected test year by this amount.

Q. IS THERE ANOTHER REGULATORY ASSET FOR DEFERRED TREE TRIMMING COSTS THAT THE COMPANY DID NOT INCLUDE IN WORKING CAPITAL BUT CALCULATED A RETURN SEPARATELY ON THE DEFERRED BALANCE FOR INCLUSION IN THE REVENUE REQUIREMENT?

A. Yes. In Exhibit A-11, Schedule A1.1, the Company calculated a return of $18,786,000 on an average balance of $204,108,000 of deferred costs for the Tree Trimming Surge program.

Q. DO YOU AGREE WITH THE DEFERRED BALANCE AMOUNT AND THE CALCULATION OF THE RETURN?

A. No. There are two problems with the amounts included in Exhibit A-11, Schedule A1.1. First, the Company included $87.0 million of additional tree trimming surge costs in 2025 on the presumption that its previously forecasted surge costs are insufficient to complete the surge program and it needs an additional $110 million between 2025 and 2026 to finish the program. The second problem is the Company's use of a rate of return of 9.20% on

the deferred amount, which is the Company's long-term permanent capital pre-tax rate of return in this rate case. The Commission has repeatedly ruled that the appropriate interest rate to apply to the deferred tree trimming costs is the short-term interest rate. In rate case after rate case, the Company does not seem to want to accept that decision and repeatedly proposes the permanent capital rate of return or the overall pre-tax rate of return, instead of the short-term debt rate, in clear violation of the Commission's orders on this matter.

Q. PLEASE DISCUSS FURTHER YOUR OBJECTION TO THE INCLUSION OF THE ADDITIONAL $87.0 MILLION OF TREE TRIMMING COSTS IN THE REGULATORY ASSET.

A. Beginning on page 15 of her direct testimony, Ms. Rachel Steudle presents an assessment of the Tree Trimming Surge program. Her conclusion is that the 7-year surge program will now cost nearly $1.4 billion, or $251.2 million more than forecasted when the Company proposed the program in 2018 in Case No. U-20162. Ms. Steudle blames higher costs to perform regular cycle clearing of trees and vegetation after the initial surge clearing, higher costs paid to contractors to perform tree trimming, additional costs for spot clearing, additional costs for the Detroit Tree Trimming Academy, and of course inflation.

Ms. Steudle reports that $90 million of the money the Company over-earned during the Covid-19 pandemic helped to offset part of the $251.2 million in additional costs, and with

forecasted efficiencies and a new focus on risk-based tree clearing, she believes an additional $110 million in funding should be sufficient to complete the surge.

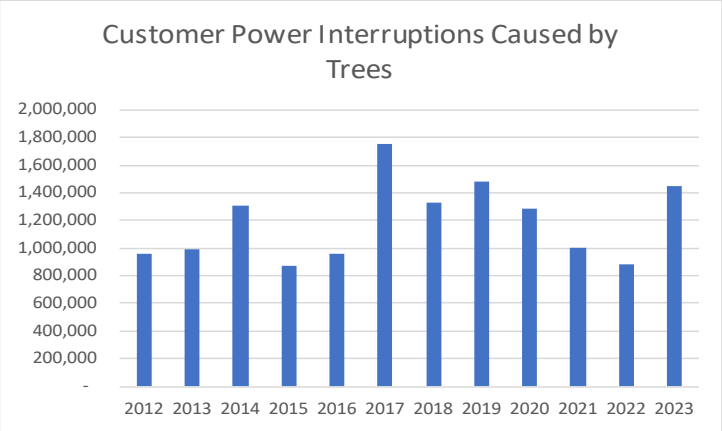
Q. WHAT IS YOUR ASSESSMENT OF THE EFFECTIVENESS OF THE SURGE PROGRAM AND THE REQUEST FOR INCREASED SPENDING ON THE PROGRAM?

A. The $1.4 billion spent on tree trimming from 2019 to 2025 is significantly understated. This amount includes only O&M costs and deferred costs under the surge program. The Company did not include in this amount the additional $496 million spent on tree trimming as part of capital programs when electrical lines and related facilities are replaced or upgraded, which also helps with managing tree growth and avoiding future power outages. Therefore, the full cost of tree trimming over the seven-year period from 2019 to 2025 will be closer to $1.9 billion.

The question then is, what has the Company accomplished with the trimming surge and the $1.9 billion in spending? In discovery, the Attorney General asked the Company to provide the number of power outages caused by trees and vegetation that occurred annually in the last 12 years, from 2012 to 2023, to get a clear perspective on whether the surge and other tree trimming activities have made a significant and clear impact in reducing power outages caused by trees and vegetation. The Company was also asked to provide the number of catastrophic storms and grey days each year to better assess the circumstances faced by the Company during those years. The Company refused to provide data on the

catastrophic and grey days, claiming the information was irrelevant to the topic of tree trimming effectiveness and the conclusions reached on the surge.[45]

However, the Company provided the number of customer interruptions caused by trees and vegetation annually from 2012 to 2023.[46] The following chart shows the number of power outages by year.



Year	Power Outages
2012	959,883
2013	991,109
2014	1,303,242
2015	870,802
2016	957,896
2017	1,748,339
2018	1,326,949
2019	1,477,637
2020	1,287,891
2021	1,003,029
2022	879,774
2023	1,445,908

Although the number of power outages caused by tree seems to be declining from 2019 to 2022, the numbers during this period are the same if not higher than they were during 2012 to 2016. In 2023, the number of power outages caused by trees reverted back to the 2019 level, despite hundreds of millions of dollars spent on tree trimming in the intervening years from 2019 to 2023. If there was a test of the effectiveness of the surge program, it was in 2023, when a severe storm and other large storms provided a clear opportunity to

[45] Exhibit AG-23 includes DR AGDE-4.157b.
[46] Id. includes DR AGDE-4.157a.

gauge whether the increased tree clearing is making a difference. The answer from the data shown above appears to be no.

In her direct testimony, Ms. Steudle states that in 2023 the Company discovered that the costs for on-cycle clearing were running higher than expected. However, data provided by the Company about the cost per mile by year from 2019 to 2023 for the surge program and on-cycle clearing shows a different story. Although in 2023, on-cycle tree trimming costs per mile jump by 41%, from $18,037 in 2022 to $25,496 in 2023, the cost per mile for the surge program increased by 53% in 2022, from $28,507 in 2021 to $43,695 in 2022.[47] Therefore, the Company should have had indications as early as 2022 that tree clearing costs were escalating significantly and could have taken corrective action.

Ms. Steudle attributes part of the increase in tree trimming costs to paying premiums to attract contractors to participate in the Company's tree trimming program. This has certainly been a big contributor to the cost increase and an area that needs special attention and corrective action. During the five years from 2019 to 2023, the Company paid premiums of $80.7 million to up to seven contractors at an average annual premium per contractor of between $1.2 million to $4.2 million. For 2024 and 2025, the Company forecasted payments of an additional $34.5 million to four contractors for an average annual amount of $4.3 million per contractor. In total, the Company expects to pay $115.2 million in contractor premiums over the seven-year period from 2019 to 2025.[48] In

[47] Id. includes DR AGDE-4.159d.
[48] Id. includes DR AGDE-4.163a and b with attachment.

contrast, in Case No. U-20162 the Company initially forecasted that it would incur $45.5 million in contractor premiums. The latest forecast is an alarming 153% increase in additional costs paid to a handful of contractors. The Company needs to take corrective steps to significantly mitigate or eliminate these extra costs for 2024 and 2025.

Q. ARE THERE OTHER COST INCREASES AND DEVELOPMENTS WITH THE SURGE PROGRAM THAT RAISE CONCERNS AND REQUIRE REMEDIAL ACTION?

A. Yes. Included in the $87.0 million of additional surge program costs is a $4.1 million increase in spending for the Detroit Tree Trim Academy. In discovery, the Attorney General asked the Company to provide the number of prospective tree trimmers trained, the number that successfully made it through the program, and the number that are still part of the trimming program. The data provided by the Company shows that of the 221 participants that enrolled and were trained from 2021 to 2023, only 74 are still working in the tree trimming program. This is a retention rate of 33%.[49] Such a low retention rate cannot be considered a success for the millions of dollars spent on the program and the *additional* $4.1 million that the Company wants to allocate to it in 2025. The Company should look at either significantly restructuring the program to at least double the retention rate or, if that goal is not achievable, shut down the academy and reassign those dollars to hiring trained tree trimmers or not spend them at all.

[49] Exhibit AG-24 includes DR AGDE-4.164b.

Another revelation from Ms. Steudle's testimony was the low number of trees actually removed through the surge program versus the number initially forecasted in Case No. U-21062. The Company had targeted to remove between 443,704 and 866,781 trees annually from 2019 to 2023.[50] In reality, the Company removed only between 38% and 48% of the planned numbers. In providing this information in response to discovery, the Company could not identify the specific reasons why so few trees were removed. The Company admits in another discovery response that removing trees minimizes the future workload of on-cycle trimming by decreasing the number of trees that will need to be trimmed in future years.[51] This is again another case of the Company spending more and accomplishing less than forecasted.

Lastly, the Company now wants to change its strategy and use a risk-based approach to tree trimming. Why the Company has not done this previously is a mystery. To implement this new strategy, the Company believes it needs to invest in Lidar technology, along with a risk prioritization model, at a cost of $6.9 million, which the Company included in capital expenditures for 2022 and 2023 in Exhibit A-12, Schedule B5.4, line 24.[52] Asked in discovery if it had performed a cost/benefit analysis to justify the new technology and program, the Company stated that it had not done so and claimed an unsupported 5% reduction in tree trimming costs going forward.[53] In other words, there is no basis or

[50] Id. includes DR AGDE-4.161c and d
[51] Id.
[52] Rachel Steudle direct testimony at page 31.
[53] Exhibit AG-24 incudes DR AGDE-4.166b and c.

indication that this revamped risked-based program will create any new financial benefits for customers to improve on the shortcomings of the current surge program.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A. The Company has not made a compelling and convincing case that increasing the amount to be spent on the surge program by $87 million in 2025 and an additional $23 million in 2026 to be charged to O&M expense is advantageous to customers. The evidence points to no significant reductions in power outages caused by trees and vegetation, and instead to significant cost overruns with contractors and other ineffective support programs.

Therefore, I recommend that the Commission reject the Company's proposed increase of $87.0 million in deferred costs in 2025 for the surge program.

Additionally, the Commission should remind the Company once more that the appropriate interest rate to be applied to the deferred costs under the Tree Trimming Surge program is the short-term debt interest rate, which in this rate case is 5.76%, according to page 1 of Exhibit A-14, Schedule D1. The lower interest rate and the removal of the $87.0 million from the average deferred balance, results in a return on the deferred tree trimming costs of $9,900,000, as calculated in Exhibit AG-25. This amount is $8,886,000 lower than the $18,786,000 forecasted by the Company. Therefore, I recommend that the Commission remove the $8,886,000 from the Company's proposed revenue requirement in this rate case.

Furthermore, I recommend that the Commission remove the $3,078,000 in capital expenditures for 2022 and the $3,824,000 for 2023 pertaining to the Tree Trim Risk Prioritization model because the Company did not perform a cost/benefit analysis and did not justify that the model and related expenditures are economically beneficial to customers.

VI. Cost of Capital

A. Capital Structure

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

A. I am recommending that the capital structure shown on page 1 of Exhibit AG-26 be used in this case. Lines 1 and 3 show the projected long-term debt and common equity permanent capital of the Company for the test period ending December 2025. The permanent capital balances in this exhibit reflect a 50%/50% capital structure, which are the same percentages reflected in Company Exhibit A-14, Schedule D1. The result is a capital structure with 50% common equity and 50% long term debt, which reflects the capital percentages approved by the Commission in the Company's last general rate case in Case No. U-21297.

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

A. No.

B. Cost of Capital

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

A. I am recommending an overall return on capital of 5.67%, which includes a return on common equity of 9.85%, as shown in Exhibit AG-26.

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

A. I utilized the 4.24% rate determined by Company witness Timothy Lepczyk.

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

A. For Short Term Debt and Deferred Taxes, I utilized the cost rates recommended by Company witness Lepczyk. For JDITC, I used the long-term debt and common equity rates I have proposed applicable to this case.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-26?

A. To develop the overall cost of capital on line 11, 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 5.67%.

Regarding the pretax weighted cost of capital on line 11, column (h), I 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 7.02% in column (h).

Q. WHAT GENERAL PRINCIPALS 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 stated 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-27.

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 flows from any enterprise may be over time. Because of this uncertainty, most financial experts will not rely solely on any one particular method. To determine the cost of common equity, I have utilized three approaches to determine this cost. These are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and a Utility Risk Premium approach. These methodologies have previously been accepted by the Commission and have generally been accepted by regulatory commissions in other jurisdictions in the United States. Also, I considered the current circumstances in the Capital Markets and any potential changes in the risk profile of DTE Electric and the current state of the Michigan economy. While Exhibit AG-27 shows a calculated cost of common equity of 9.80%, from the three approaches, I recommend an allowed rate of return on equity of 9.85%, which reflects rounding the result up. In connection with these methods for determining the cost of common equity, I have considered the cost of common equity for a proxy group of peer companies.

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

A. As reflected in Exhibit AG-33, to develop my peer group I started with the 38 electric utility companies followed by the Value Line Investment Survey. From this group of companies, I removed six companies due to size considerations, which include Duke, Exelon, Nextera, and Southern Company (much larger companies), as well as two smaller companies with annual revenues at $1.0 billion or less (MGE Energy and Unitil). Next, I removed three companies whose dividends are not growing and two other companies, Fortis (a Canadian company) and Sempra Energy due to its foreign investments. Three other companies that I removed are Hawaiian Electric, Eversourse Energy, and Edison International. These companies face higher risks due to wildfire liabilities and the construction of off-shore wind electric generating facilities. Two other companies I removed are Otter Tail and Nextera Energy. Nextera (parent of Florida Power & Light) was removed due its growing non-utility investments primarily in the power generation business, which is currently more than 40% of the company's total Property Plant & Equipment assets,[54] and its high-risk profile due to severe hurricanes. Otter Tail was removed because its operating income from non-utility operations are now 75% of the total company income.[55] Its plastics and manufacturing businesses have grown significantly

[54] Nextera's 2023 Form 10-K Financial Statements show Property Plant & Equipment of $125.8 Billion for the parent company and $70.6 billion for Florida Power & Light (basically a 55%/45% utility / non-utility split).
[55] See pages 29 to 31 of the 2023 Otter Tail Form 10-K filed with the SEC.

and its business profile no longer meets that of a typical peer utility. Several other companies I disqualified are involved in M&A activity or corporate reorganizations, or are companies facing earnings growth challenges.

Exhibit AG-33 shows the starting group of 38 electric utilities I initially considered with the analysis to arrive at the proposed peer group of companies. The result is the group of ten companies shown in Exhibits AG-28 and AG-29 all of which have growing earnings and dividends, and are comparable to the Company.

Q. HOW DOES YOUR PEER GROUP OF TEN COMPANIES COMPARE TO THE COMPANY'S ELECTRIC PEER GROUP?

A. The Company's electric peer group presented by witness Villadsen consists of a group of 25 companies shown on page 30 of her testimony. This group includes eight of the companies in my peer group plus (a) five companies I removed due to size considerations; (b) four companies: American Electric Power, ALLETE, CenterPoint Energy, and WEC Energy Group, which I excluded due to reorganization / M&A considerations; (c) a number of companies, OGE Energy, Pinnacle West, Evergy, and Entergy, which I removed due to growth challenges or other irregularities; and (d) Edison International, due to uninsured wildfire risk and thus dividend risk. Edison International recorded after-tax charges to earnings of $3.8 billion for wildfire and mudslide damages in 2021.[56] Many of

[56] See Edison International 2021 Form 10-K, page 10.

the companies identified above have extraordinary and unique risks or uncertainties and should not be included in the group of peer companies.

Q. ON PAGE 28 OF HER TESTIMONY, WITNESS VILLADSEN EXPLAINS HER SCREENING CRITERIA FOR DEVELOPMENT OF HER PEER GROUPS. WHAT IS YOUR VIEW OF THESE SCREENING CRITERIA?

A. Dr. Villadsen specifies five criteria. Three of these requirements include (a) investment grade status; (b) a market capitalization of at least $300 million[57]; and (c) the availability of sufficient data for estimation. I will point out that most of the companies followed by Value Line meet these criteria and therefore the use of these criteria by Dr. Villadsen accomplishes little if anything different to select a proper peer group.

Her fourth criterion is that the peer company "must pay dividends with no dividend cuts in three years." Again, most utility companies meet this criterion. Her fifth criterion is that the peer company "cannot have engaged in substantial merger, acquisition or divestiture activity for three years." In this regard, I will point out that two of her peer companies (American Electric Power and CenterPoint Energy) have been looking to sell assets for some time to bolster their balance sheets and reduce risk. These potential transactions can affect the stock price.

[57] Unitil is the smallest electric utility followed by Value Line with a market capitalization of $650 million.

Dr. Villadsen's peer group selection process does not reflect sufficient rigor, often failing to follow even her own criteria. The net result is that certain high-risk companies, as well as poorly matched companies, are included in her peer group to provide an unreliable cost of equity capital.

The Commission should reject the Company's proposed peer group and the cost of equity capital derived from those groups of companies.

Discounted Cash Flow (DCF) Approach

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 of equity. Expressed mathematically, the resulting equation can be reconfigured to solve for the required rate of return. 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

Generally, the "D" or dividend is known and the "P" or stock price is also known as the stock trades each day. Also, recent growth in the dividend is known or estimates of growth

furnished by stock analysts can be relied upon with some degree of certainty. With this information, one can solve for "R", which is the required rate of return.

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-28. The stock price information in column (c) on this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from May 1 to June 12, 2023. The annual dividend in column (d) is the average projected dividend level for 2024 and 2025 as calculated by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on Value Line 2024 projections of earnings per share through the 2027 – 2029 period, and Yahoo Finance analysts' projected growth in earnings per share over the next five years. The resulting calculation of the DCF Method indicates an average required return on common equity of 9.26% for the proxy group. In contrast, Dr. Villadsen proposes a simple DCF ROE result of 11.2% on page 38 of her testimony based on her electric peer group.

Q. **PLEASE EXPLAIN WHY WITNESS VILLADSEN'S 11.2% DCF COST OF EQUITY IS MUCH HIGHER THAN YOUR 9.26% DCF RESULT.**

A. There are two main reasons. First, as noted earlier, Dr. Villadsen included many inappropriate companies in her peer group, which improperly boosted the ROE calculation. Six of these companies have inflated ROE results between 11.0% and 16.7% (Duke Energy, Exelon, NextEra Energy, OGE Energy, Pinnacle West, and the Southern

Company). Second, she again applied her ATWACC adjustment, which the Commission has consistently rejected.

Q. PLEASE EXPLAIN WHAT THE RESULTS OF WITNESS VILLADSEN'S ANALYSIS WOULD BE IF SHE EXCLUDED THE SIX INAPPROPRIATE COMPANIES YOU HAVE IDENTIFIED ABOVE FROM HER ANALYSIS.

A. If we isolate the six companies in the calculation of the DCF ROE, the average ROE result for the six companies is 12.85%. Had Dr. Villadsen excluded those results, her calculated ROE for the remaining companies in her peer group would have been 9.7%. Her calculations for these companies are often based on stale or inflated earnings data and dividend yields. For example, she calculated a 13.4% DCF ROE for Exelon based on stale information. Her growth rate for Exelon shown on Exhibit A-14, Schedule D5.6, Panel A is 9%. It is worth noting that this case was filed in late March 2024 and the information of the peer companies shown in the Company's exhibits is now approximately six months old. Moreover, a 9% growth rate for Exelon (an entirely regulated utility) is excessive and unlikely to be achieved in the long-term.

In contrast, more recent data as of May 10, 2024 shows a dividend yield for Exelon of 4.1%. For earnings growth, Value Line shows annualized EPS growth of 5.5% based on EPS of $2.38 in 2023, growing to $3.10 in 2028.[58] As of early July 2024, Yahoo Finance shows that analysts forecast a 4.2% growth rate for the company for the next five years.

[58] Value Line Investment Survey page 140 dated May 10, 2024.

These facts suggest a DCF ROE rate of approximately 8.3% to 9.6%, which is well below the 13.4% calculated by Dr. Villadsen.

Similarly, the OGE Energy DCF ROE of 16.7% in the Company's calculations is based on stale information. The growth rate for OGE Energy, according to witness Villadsen, is 11.3%. This growth rate is also inflated and unlikely to be achieved in the long-term given that the company is a low-growth, pure combination utility. More recent information shows that OGE Energy's dividend yield is 4.7%. When added to the Value Line EPS growth of 5.7%, the resulting DCF ROE rate is 10.4%, instead of the Company's calculated 16.7%.[59]

Q. WHY ARE THE ATWACC DCF ROE RESULTS CALCULATED BY THE COMPANY HIGHER THAN CONVENTIONAL DCF RESULTS?

A. The key factor causing the escalation in the ATWACC ROE is the use of the stock market value relative to the book value of the common equity for each company in the analysis. Given that stock prices per share are higher than the book value per share, the ATWACC approach inflates the calculated ROEs.

The Commission should recognize the inherent circularity of the ATWACC process. For example, if the ATWACC approach was to become universally embraced by regulatory commissions, the ROEs awarded in regulatory proceedings would increase. These inflated

[59] Value Line Investment Survey page 913 dated June 7, 2024.

ROEs would then result in higher utility earnings, stock prices, and higher market to book ratios for utility common stocks. The subsequent calculated ROEs in new rate cases under the ATWACC method would then produce even higher awarded ROEs because the ATWACC would use the higher stock market equity capitalization.

It is likely because of this cost inflating circularity and the complexity of the methodology that the ATWACC approach has not been embraced by state regulatory commissions. In fact, asked to provide evidence that the methodology has been accepted by state regulatory commissions, the Company could not identify any situations.[60] These instances are (1) property taxation disputes in Colorado; (2) Florida's regulation of small water companies; (3) a valuation dispute before the FERC; (4) revenue adequacy hearings for railroads; and (5) a revenue adequacy hearing involving Alabama Power related to its special rate RSE. Nowhere in her testimony does witness Villadsen mention any state regulatory commissions in the United States endorsing ATWACC in a general rate case proceeding. Therefore, the Commission should disregard the ATWACC approach to calculate the DCF cost of common equity.

Q. HAS THE COMMISSION EXPRESSED ITS VIEWS REGARDING THE ATWACC APPROACH AND FINANCIAL LEVERAGE ADJUSTMENTS?

[60] DR AGDE-1.9a.

A. Yes, in one of the Company's recent rate cases both the ALJ and the Commission stated that such adjustments were not appropriate. The Commission's order in that case states the following.

> Further, the Commission adopts the ALJ's findings and conclusions regarding DTE Electric's financial leverage adjustments. The Commission again emphasizes that adjusting for financial risk or applying financial leverage adjustments is not appropriate. While there was some dispute with respect to the terminology used to describe the company's adjustment, the Commission agrees with the ALJ's determination that the parties were referring to the same adjustment. *See*, PFD p. 446, n. 1289. As quoted by the ALJ at page 447 of the PFD, in the December 9 order, the Commission held that it "has consistently taken a traditional approach to establishing ROE, consistent with the principles of Hope Natural Gas and Bluefield Waterworks" and that the application of ATWACC or other financial leverage adjustments "may excessively inflate ROEs, stock prices, and market-to-book ratios for utilities…. Therefore, the ALJ's rejection of the Company's financial leverage adjustment is well supported by the record and Commission precedent….[61]

The same approach has been proposed by the Company in this rate case and the Commission should reach the same conclusion.

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 growth prospects by security analysts, which influence the beliefs of investors. I will point out that the forecasted growth rates in my proxy group include some high growth rates, which in some cases are between 6% and 7%. While these earnings growth rates may materialize in the short term, they may not be sustainable long-term growth rates for electric utilities given that customer and

[61] Case No. U-20836, MPSC Order dated November 18, 2022 at page 241.

revenue growth continue to be barely in low single digits. As such, the results of the DCF analysis in some cases reflect a return on equity rate that is somewhat higher than what investors currently expect in the long term. Nevertheless, I place a fairly high degree of reliability on the DCF results when considered in conjunction with the results of other approaches to determining the cost of common equity.

Capital Asset Pricing Model Approach

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL 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. Some securities vary less in price over

time than the overall market. In these cases, the Beta will be less than 1.00. Securities that vary over time more than the overall market will have a Beta that is greater than 1.00.

Q. PLEASE EXPLAIN EXHIBIT AG-29 AND THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-29 shows the results of the CAPM method based upon (1) a projected 4.05% risk free rate as explained below; (2) Beta information available from Value Line; and (3) the historical Market Risk Premium (R_p) of 7.17% based on the 2023 Ibbotson Classic Yearbook.

Regarding the use of a risk-free rate for CAPM purposes, I used a 4.05% rate determined from information provided by the Company showing projected 10-year U.S. Treasury rates.[62] First, I used the January 1, 2024 Blue Chip average projected rate for 2025 of 3.7%. Second, I used the May 10, 2024 Blue Chip average projection for 2025 of 4.0%. To these forecasted rates, I added 20 basis points to take into consideration the actual average spread between the 10-year and the 30-year U.S. Treasury rate during the first half of July 2024, which produces 30-year forecasted U.S. Treasury rates of 3.9% and 4.2%. Recognizing the uncertainty in the capital markets as to when the Federal Reserve bank will reduce interest rates, I believe that taking an average of the two forecasted rates is appropriate. The result is a 4.05% risk-free rate for the 30-year U.S. Treasury bond.

[62] DR AGDE-1.4 included the Blue Chip reports provided by the Company.

As shown in Exhibit AG-29, I added the beta adjusted peer group risk premium of 6.52% to the 4.05% risk-free rate, to arrive at the 10.57% ROE rate under the CAPM approach.

Q. PLEASE COMMENT ON WITNESS VILLADSEN'S CALCULATIONS OF CAPM COMMON EQUITY COST RATES FOR HER ELECTRIC PEER GROUP RANGING FROM 10.9% TO 11.7%.

A. In Figure 10 on page 35 of her direct testimony, witness Villadsen presents four different CAPM estimates for her electric sample group. In addition, she presents an equal number of estimates under her ECAPM approach, but the ECAPM results are essentially the same as the CAPM estimates. The Commission should not rely upon any of these CAPM and ECAPM results, because all of the estimates have been determined utilizing the Hamada approach with leveraged betas. The Hamada approach is similar to the ATWACC approach, and both of these methodologies lead to faulty and inflated results. In my testimony above, I explained the Commission's previous stated position on these market-leveraged adjustments.

Witness Villadsen's CAPM estimates on page 35 of her testimony show rates calculated under two different scenarios, with market risk premium (MRP) rates based on the traditional historical Ibbotson series and alternatively based on Bloomberg's MRP estimates. On page 34 of her testimony, she states that these two scenarios provide "a range of cost of equity estimates" which are 10.9% to 11.7%.

However, her CAPM results before applying the Hamada adjustment are 10.2% to 11.0%, as shown on her Exhibit A-14, Schedule D5.11 (Panel A and Panel B) at the bottom of the first column in each case. As can be seen in the table below, the midpoint of this range at 10.6% is very similar to my own result of 10.57% without the Hamada adjustments.

Villadsen Figure 10 CAPM ROEs Adjusted	**Scen. 1**	**Scen. 2**
Figure 10 CAPM ROEs (Line 1)	11.70%	10.90%
Less Hamada Impact from below	-0.70%	-0.70%
Adjusted CAPM ROEs	**11.00%**	**10.20%**
Midpoint of Scenario 1 and Scenario 2	**10.60%**	

Additionally witness Villadsen recommends that a further downward adjustment to the CAPM results should be considered by the Commission under the ECAPM method. She proposes reducing one of her outcomes by 0.1% to reflect the ECAPM. This adjustment is subjective, unconventional, and not supported. As I have stated in other cases brought before the Commission by the Company, I remain opposed to the ECAPM. However, since it has no practical importance in this case, I am not dedicating additional testimony to addressing the shortcomings of ECAPM.

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 is assumes

that the entire risk of a stock can be measured by the "Beta" component and as such the only risk an investor faces is created by fluctuations in the overall market. In actuality, investors take into consideration company-specific factors in assessing the risk of each particular security. As such, I give the CAPM approach less weight than the DCF approach in determining the cost of common equity.

Utility Risk Premium Approach

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

A. In general, one can estimate the cost of common equity by estimating three components and adding them together. The three components are (1) the risk-free rate of return on 30-year U.S. Treasury Bonds; (2) the historical differential between yields of the rated utility bonds of the Company and the 30-year U.S. Treasury Bonds (risk-free rate); and (3) the average return differential of utility common stocks over utility bonds.

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-30 shows the three components required to estimate the cost of common equity under this approach. The results for this approach reflect a return on common equity of 10.1%. To arrive at this result, I used the 4.38% historical spread of electric utility common stock returns relative to utility bonds. I also used a 1.67% average spread for "A" rated and "BBB" rated utility bonds over the U.S. Government bonds (the risk-free

rate). For the risk-free rate, I used the projected 30-year Treasury rate of 4.05% discussed under the CAPM section of my testimony.

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

A. No, not in the traditional sense of measuring achieved returns on utility stocks relative to an interest rate benchmark such as utility bonds.

Q. PLEASE COMMENT ON WITNESS VILLADSEN'S TESTIMONY ON PAGES 38 THROUGH 40, STARTING UNDER THE HEADING "RISK PREMIUM APPROACH AND COST OF EQUITY ESTIMATE" ON PAGE 38?

A. In her testimony, Dr. Villadsen states that she compared authorized ROEs from electric utility rate case decisions to 20-year U.S. Treasury bonds from 1990 to 2023. She ran a regression model with this data and observed that ROE rates have fallen more slowly than treasury bonds. Based on this analysis she concludes that an ROE of 10.5% for electric utilities would be appropriate based on the 20-year forecasted U.S. Treasury rate of approximately 4.30%.

There are several flaws with this analysis. Chief among them is the premise that treasury bond yields are the primary driver in ROE decisions by regulators. It is also not connected to stock market performance or investor expectations of returns on investment. This analysis has no validity as a tool to determine the ROE to be established in rate proceedings. Regulators approach the serious business of establishing a ROE based on

many factors and often exercise "gradualism" in the process as well. The Commission should give this analysis no weight in this case.

Q. **HOW HAS THE ECONOMIC AND INTEREST RATE ENVIRONMENT CHANGED IN RECENT YEARS FOR THE COMPANY?**

A. The U.S. economy and the Michigan economy have generally recovered from the 2020 recession caused by the Covid-19 pandemic, thanks in part to the accommodative stance of the U.S. Federal Reserve Bank during 2020 and 2021 by reducing interest rates. More recently, in late 2022 and early 2023 inflation has been a concern. To combat this threat, the Federal Reserve Bank increased short term interest rates. Inflation in late 2023 and so far in 2024 has fallen, with the CPI reflecting monthly rates of 0.3%, zero, and -0.1% for the three months of April, May, and June 2024.[63] Sentiment in the June/July 2024 period is fairly universal that the Federal Reserve will soon begin to cut short-term interest rates and this should result in falling long-term interest rates as reflected in the Blue Chip reports mentioned earlier in my testimony. Lower interest rates will benefit the Company with lower financing costs and lower the cost of equity capital.

In my calculations on the cost of equity in this rate case for both the CAPM and Utility Risk Premium methods, I reflected those expectations with a projected 4.05% risk free rate for the U.S. 30-year Treasury Bond for the projected test year.

[63] U.S. Bureau of Labor Statistics press release of July 11, 2024 and Table A included therein.

The Company's access to the capital markets has remained strong, as witnessed by DTE Electric's issuance in February 2024 of $500 million of new 10-year long-term debt at a rate of 5.2% and $500 million of 2-year debt at a 4.85%.[64] The Company's senior secured debt ratings are A/Aa3 and its commercial paper program is rated P-1 (highest) by Moody's Investor Service. Also, the Company's parent, DTE Energy, accessed the capital markets in February 2024, issuing approximately $1.2 billion of 5-year long-term debt at a rate of 5.1% and again in April 2024 issuing $850 million of 10-year long-term debt at a rate of 5.85%.[65]

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS GRANTED TO ELECTRIC UTILITIES IN 2022 AND 2023.

A. In Exhibit AG-31, I have segmented the ROE decisions into two groups. Pages 1 and 2 of Exhibit AG-31 show the most recent ROE decisions with ROE rates granted below 9.9%. This by far represents the largest group of ROE decisions with 23 of 32 decisions during 2022 and 38 out of 48 decisions in 2023. For the grouping of companies with ROE rates below 9.9%, these rates range from a low of 7.85% for Ameren-Illinois to a high of 9.80% for Wisconsin Power in Light. The average ROE for this group was 9.29% in 2022 and 9.48% in 2023.

[64] See DTE Energy 1st quarter Form 10-Q filed with the SEC.
[65] See Forms FWP dated February 12, 2024 and April 29, 2024 filed with the SEC

Page 3 of the exhibit is a summary of all ROE rates granted, including those at 9.9% and above, which in 2022 and 2023 was limited to eleven ROE decisions in California and eight other ROE decisions in other jurisdictions, including three in Michigan. Inclusive of these additional utilities, the overall average ROE rate was 9.54% in 2022 and 9.66% in 2023.

The information provided in this exhibit is based on ROE rates granted by state regulatory commissions in general rate cases for electric utilities during 2022 and 2023 and published by Regulatory Research Associates, a respected and independent regulatory research firm.

From this information, it is apparent that the 9.9% ROE granted to DTEE in 2023 and similarly granted to other utilities in Michigan are outlier ROE rates considerably higher than the equity returns granted by state regulatory agencies for most other electric utilities. Other outlier ROE rates of 9.9% and higher granted to electric utilities are mainly in California (eleven decisions), Ohio, North Carolina, Georgia, Alaska, and four decisions issued by the Michigan Commission.

Exhibit AG-31 also includes information regarding debt financing subsequent to the issuance of the rate orders. It is clear from this information that the debt capital markets have remained strong and continue to provide debt capital at competitive interest rates to utilities with authorized ROEs well below the average ROE rate of 9.48% in 2023.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE OF 9.85% IN THIS CASE WILL LEAD TO IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?

A. No. In recent general rate case proceedings, the Commission seems to have been persuaded by the applicants' arguments that they should receive an ROE rate of 10% or higher to ensure the financial soundness of the business and to maintain a strong ability to attract capital in addition to being compensated for risk. Pages 1 and 2 of Exhibit AG-31 show several utilities that have accessed the capital markets at competitive interest rates since receiving an ROE substantially below 9.9% as well as below the average rate of 9.50%.

Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs below 10%. On the contrary, stock investors continue to migrate to utility stocks recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-39 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past two years reflecting ROEs ranging from 7.85% (Ameren-Illinois in 2022) to 9.9% (CMS Energy in 2023). Yet this group of companies has an average ratio of Market price to Book common equity value of more than 1.6 times book value, indicating that utilities are earning returns above the investor expected cost of equity on book value.

This information is provided to dispel the myth that the Company must receive an ROE rate 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 Electric. Other electric and gas utilities face the same issues and are able to raise capital with ROEs at or below my proposed ROE rate of 9.85%. Therefore, this issue is another "red herring."

Q. HAVE YOU DETERMINED THE RETURN ON EQUITY RATES GRANTED TO UTILITIES IN SURROUNDING STATES OUTSIDE OF MICHIGAN DURING 2023?

A. Yes. Exhibit AG-32 shows nine decisions rendered in 2023 in surrounding states which range from a low of 8.72% to a high of 9.80%, and which average to 9.49%. Even in Wisconsin, where rates were recently as high as 10%, ROE decisions in 2023 declined to 9.7% and 9.8%.

Q. WOULD A REDUCTION IN THE COMPANY'S ROE TO 9.85% HAVE AN IMPACT ON THE COMPANY'S DEBT RATINGS?

A. It is unlikely that a downgrade would occur simply due to a slightly lower ROE rate. Moody's rates the Company's debt as "Aa" and views the Michigan regulatory environment as constructive. A review of the most recent Moody's report on DTEE shows that the Company achieved a 20.2% CFO pre-WC to Debt ratio during the twelve months

ended March 2023. This is a key ratio that Moody's uses to evaluate the Company's credit worthiness. It is Moody's position that ratio results under 21% for a sustained time could lead to a downgrade of the Company's debt. I will point out, however, that DTEE's capital structure was more leveraged during this timeframe than the 50%/50% debt and common equity used to set rates in the Company's last two rate cases.

In Exhibit AG-35, I calculated a pro-forma CFO pre-WC to Debt ratio based on the Company receiving and earning an ROE rate of 9.85%. The calculations in the exhibit start with the actual ratio for the twelve months ended March 2023 and the adjustments needed to reflect a 50% common equity ratio and a 9.85% ROE rate. After making these adjustments the CFO pre-WC to Debt ratio increases from 20.2% to 22.3%, which is comfortably above the 21% long-term downgrade threshold set by Moody's.

Q. ON PAGE 52 OF ITS SEPTEMBER 13, 2018 ORDER IN CASE U-18999, THE COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO AUTHORIZE A 10% ROE RATE. SHOULD STOCK MARKET VOLATILITY OR THE VIX INDEX BE A CONCERN IN ESTABLISHING A FAIR ROE FOR THE COMPANY?

A. No. Historically, the stock market has been very volatile. Currently, this is measured by the VIX, which portrays volatility over the next 30 days. Company witness Villadsen addresses the VIX on page 22 of her testimony, suggesting that the VIX is somehow

relevant. She reports the VIX was "…higher at about 22 at the end of October 2023…."[66] In discovery, the AG asked the Company to provide any long-term projections of the VIX for the projected test year. In response, witness Villadsen stated that she did not have a long-term projection of the VIX.[67]

The key point that needs to be made is that the VIX is telling us something about risk in the market over the next 30 days and not risk several months into 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.

Furthermore, in Exhibit AG-36, I 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."

I will submit that those who invest money in 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 as much volatility as the general stock market. This is reflected in the average beta of 0.91 of the utility peer group used in the CAPM ROE rate calculation discussed earlier. This is in contrast with the general stock market value

[66] Villadsen testimony at page 22, lines 8 and 9.
[67] DR AGDE-1.7.

of 1.00. Therefore, the Commission should not give any weight to arguments that the Company's ROE rate should reflect investors' concerns with stock market volatility.

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

A. In Exhibit AG-27, I summarized the cost of equity rates from the three methods I used. The range of returns for the industry peer group is from 9.26% at the low end, using the DCF approach, to 10.57% at the high end using the CAPM approach.

As explained earlier in my testimony, I give more weight to the DCF method as a more reliable approach to estimating the cost of equity for utilities, which in my analysis is 9.18%. In this regard, on line 4 of Exhibit AG-27, I calculated a weighted return on equity of the three methodologies using a 50% weight for DCF and 25% for each of the other two methods. The result is a weighted return on equity of 9.80%. To this base cost of equity capital I added an additional premium adjustment of 5 basis points, to arrive at a recommended ROE rate of 9.85% for this rate case. The additional 5 basis points provide an added cushion to the ROE rate, should interest rates fall slower than anticipated.

Michigan utilities currently enjoy some of the highest ROE rates among utilities in the country. As shown in Exhibit AG-31, ROE rates granted to Michigan utilities in 2022 and 2023 are at the highest end of the range among most utilities in the country and well above the national average rate and the Midwest average of 9.50%. In prior rate cases, the

Commission has expressed a desire to gradually reduce those ROEs. This rate case provides an opportunity for the Commission to do so by setting the Company's ROE rate at 9.85%.

Q. IF THE COMMISSION APPROVES THE SAME 9.90% ROE RATE IN THIS CASE AS IT DID IN THE COMPANY'S PRIOR RATE CASE, WHAT IS THE COST TO CUSTOMERS COMPARED TO AN ROE OF 9.85%?

A. If the Commission were to grant a 9.90% ROE in this case versus a 9.85% ROE, the additional cost to customers is approximately $6.4 million annually. There is absolutely no need to burden customers with this additional cost, when historically the Company has been earning well above its authorized ROE.

I recommend that the Commission take note of the evidence and arguments I have presented in my testimony and grant the Company an ROE of no more than 9.85%.

VII. O&M Expense Adjustments

Q. WHAT AMOUNT OF O&M EXPENSE DID THE COMPANY INCUR DURING 2022 AND WHAT IS THE AMOUNT OF EXPENSE REQUESTED FOR THE 2025 PROJECTED TEST YEAR?

A. As shown in Exhibit A-13, Schedule C5, the Adjusted Historical Test Period O&M expense for 2022 is $1.224 billion. The Company forecasted that O&M expenses will increase to $1.267 billion during the test year ending December 2025. While the

Company's projected expense level represents a 3.5% increase, or $43 million, over the historical level, there are many offsetting changes which should be noted. Cost reductions of approximately $108 million are reflected in the projected test year, primarily from the closing of three power plants ($31 million), lower nuclear expenses ($47 million), the removal and deferral of pension expense, and lower OPEB expenses ($30 million). Offsetting these expense reductions is $87 million of forecasted inflation cost increases for wages and other expenses.

Q. IN YOUR ANALYSIS, HAVE YOU IDENTIFIED AREAS WHERE EXPENSES SHOULD BE REDUCED

Yes. As a result of my analysis, I have identified $123.5 million of expense reductions, which I will discuss in more detail below. Exhibit AG-37 provides a summary of my proposed adjustments.

A. Inflation Adjustments - O&M Expense

Q. HAVE YOU MADE ANY CHANGES TO THE INFLATION AND MERIT INCREASE ADJUSTMENTS TO O&M EXPENSES PROPOSED BY THE COMPANY IN THIS RATE CASE?

A. Yes. The Company used a form of blended inflation based partially upon projected CPI rates with a 16% weighting, and a 3% wage inflation rate with an 84% weighting. The development of these blended inflation rates is shown on Exhibit A-13, Schedule C5.15

and the blended rates are 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025. 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. Instead, the Commission has previously adopted the use of the CPI-Urban area inflation rates to forecast future cost increases when warranted. As discussed under the Capital Expenditures section of my testimony above, I used a forecasted CPI rate of 2.4% for 2024 and 2.2% for 2025.

The Company used the 2022 O&M expense base to develop its inflation adjustments. However, in 2023 the Company took steps to significantly reduce O&M expenses, which makes the 2022 expense amount stale and no longer reflective of the Company's cost structure for the projected test year. In calculating the appropriate amount of inflationary cost increases for 2024 and 2025, I used the actual normalized 2023 O&M expense amounts provided by the Company in response to discovery.

Q. PLEASE EXPLAIN YOUR EXHIBIT AG-38 SHOWING THE RECALCULATION OF INFLATION AT CPI RATES APPLIED TO 2023 COSTS.

A. In Exhibit AG-38, I begin in column (b) with the actual normalized 2023 expense provided by the Company. In columns (c) and (d) I applied the two-year inflation rate of 4.65% to the actual 2023 expenses to determine the proper amount of inflationary cost shown in column (d).[68] Column (e) is the sum of the inflation adjustments calculated by the

[68] The 4.65% two-year inflation rate is the result of combining CPI rates of 2.4% for 2024 and 2.2% for 2025.

Company for 2024 and 2025 and shown in Exhibit A-13, Schedule C5. The difference between the amount of inflation adjustment I calculated versus the Company's amount is shown in column (f) and totals to $14.6 million. This amount reflects the difference between the CPI rates and the blended inflation factors used by the Company and also the lower O&M expense base in 2023 versus 2022.

Accordingly, I recommend that the Commission reduce the Company's O&M expense by $14.6 million for the updated inflation adjustments for 2024 and 2025.

B. Steam Generation Expenses

Q. IN EXHIBIT A-12, SCHEDULE C5.1, THE COMPANY FORECASTED O&M EXPENSES FOR STEAM POWER GENERATION OF $213.4 MILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY'S FORECASTED AMOUNT?

A. No. Based on the more recent 2023 expense information provided by the Company in discovery, the Company's forecasted O&M expense in the Steam Power Generation area for the projected test year is excessive. The actual normalized expense for 2023 is $183.0 million, or approximately $30 million lower than in 2022, which the Company used as a basis to forecast the projected test year expense.

In Exhibit AG-39, I calculated the projected test year O&M expense using the 2023 normalized expense of $183 million. After adjusting for two years of inflation for 2024

and 2025 at the CPI rates, I arrived at a 2025 expense amount of $191.5 million. This updated forecast is $21.5 million lower than the Company's forecasted amount of $213.4 million.

My updated O&M expense reflects a more accurate forecast of the projected test year expense for Steam Generation due to recent cost reductions and power plant retirements undertaken by the Company. Therefore, I recommend that the Commission reduce the Company's forecasted O&M expense by $21.9 million.

C. Voluntary Separation Program

Q HAS THE COMPANY INITIATED ADDITIONAL COST REDUCTIONS IN 2024 THAT WILL FURTHER REDUCE O&M EXPENSE IN THE PROJECTED TEST YEAR?

A. Yes. In response to discovery, the Company stated that in January 2024, it offered a Voluntary Separation Incentive Plan to 1,025 DTE Electric employees and 1,622 DTE Corporate Services employees. Of those eligible employees, 140 DTE Electric employees and 249 Corporate Services employees accepted the separation plan, with employee reductions occurring during the first half of 2024. In the discovery responses, the Company also stated that up to $20.3 million of labor and benefit cost savings could be achieved in 2025.[69]

[69] Exhibit AG-45 includes DR AGDE-1.23c.

The preliminary cost savings for 2025 estimated by the Company are real and significant and should be included in the projected test year as a reduction of future O&M expenses. However, conservatively, I included only half, or $10.1 million, of the currently estimated cost savings of $20.3 million as a reduction to the O&M expense for the projected test year. The remaining half of the cost savings plus the cost savings that the Company will retain during 2024 will go a long way to offset the costs that the Company will incur in 2024 to achieve those savings.

Therefore, I recommend that the Commission accept this additional adjustment of $10.1 million to the forecasted O&M expense for the projected test year.

D. Tree Trimming Cost Savings

Q. DID THE COMPANY IDENTIFY CERTAIN COST SAVINGS THAT WILL BE REALIZED IN 2025 AS A RESULT OF THE SURGE PROGRAM AND ACCELERATED TREE TRIMMING?

A. Yes. Ms. Hartwick's Exhibit A-22, Schedule L1, shows cost level reductions related to the Tree Trimming Surge Program. Exhibit AG-40 shows my analysis based on the Company exhibit and a response to discovery of declining costs for reactive tree trimming, storm related tree trimming, and other distribution related costs as a result of more trees being trimmed under the surge program compared to the cost levels in 2022. Based on the information provided, my analysis shows that the Company should achieve O&M cost savings of $17.6 million as a result of the spending on the surge program from 2022 to

2025. The reduction in costs is shown on line 4 of Exhibit AG-40. The $17.6 million matches the information for O&M cost savings provided by the Company in response to DR AGDE-4.167.[70] Subtracting the $8.8 million benefit already included by the Company in Exhibit A-13, Schedule C5.6, results in an additional savings of $8.8 million, which the Company did not include in its O&M expense for the projected test year.

Therefore, I recommend that the Commission remove the $8.8 million in additional cost savings from the Company's forecasted O&M expense.

E. Credit/Debit Card Merchant Fees

Q. ARE YOU PROPOSING ANY CHANGES TO THE COMPANY'S CREDIT/DEBIT CARD PAYMENT PROGRAM OR ADJUSTMENTS TO RELATED O&M EXPENSE?

A. Yes. The Company currently allows residential and commercial/industrial (non-residential) customers to pay their electric bills with a credit or debit card. Until about 2016, the number of customers using debit and credits cards was relatively low. Subsequent to changes made to the Company's SAP system, which allowed more customers to use credit cards, the volume of credit card payments increased dramatically. For DTE Electric, merchant fees reached nearly $11.8 million in 2022 and have ebbed

[70] Exhibit AG-7.

somewhat in the past two years after the Company imposed certain limitations on the use of credit/debit cards by non-residential customers.[71]

Beginning on page 62 of her direct testimony, Ms. Pina Bennett discusses the recent history of debit/credit cards and presents data on merchant fees paid by the Company. Although, in recent years the Company has begun to limit the use of credit/debit cards for non-residential customers, the cost is still significant. For the projected test year, the Company forecasted $8,822,000 in merchant fees pertaining to residential customers and $3,474,000 for non-residential customers, for a total forecasted expense of $12,296,000.

Q. WHAT IS YOUR PROPOSAL?

A. I propose that the Commission disallow recovery of merchant fees for non-residential customers beginning with the costs included in the projected test year in this rate case. This proposal will remove $3,474,000 from forecasted expense for the projected year. Non-residential customers, which consist primarily of small to medium size commercial and industrial businesses, have more options and sophistication than residential customers to pay their gas and electric bills through other less costly means, such as Electronic Funds Transfer (EFT) and Automatic Clearing House (ACH). In response to discovery, the Company reported that an EFT or ACH transaction charge is approximately 10 to 11 cents. In contrast, the merchant fee for the use of a credit/debit card for non-residential customers

[71] Exhibit A-13, Schedule C5.7.1.

is $4.72 per transaction.[72] This large disparity in cost is not reasonable and should be avoided.

In late 2023, Consumers Energy came to the realization that removing the credit/debit card convenience fee previously charged to customers was neither sustainable nor in the best interest of the majority of its customers, due to the large escalation in merchant fees. Beginning in 2024, Consumers Energy reimposed a convenience fee for all customers, both residential and non-residential, who want to use a credit card. This is a step that the Company should evaluate in the coming months and address accordingly. With the large escalation in merchant fees in recent years, more businesses, from restaurants to retail shops, are imposing a convenience fee when customers pay for goods and services with a credit card. Of course, gasoline stations placed a premium on gasoline sales with a credit card long ago.

Therefore, at this time, I recommend that the Commission disallow recovery of the $3.5 million of merchant fees pertaining to non-residential customers so that the Company can take appropriate actions to avoid those costs beginning with the projected test year in this rate case.

[72] Exhibit AG-46 includes DR AGDE-1.28g and d. The $4.72 merchant fee is stated on page 64 of Ms. Bennett's direct testimony on line 2.

F. Uncollectible Accounts Expense

Q. PLEASE SUMMARIZE HOW THE COMPANY ARRIVED AT ITS PROPOSED $50.9 MILLION EXPENSE FOR UNCOLLECTIBLE ACCOUNTS FOR THE PROJECTED TEST YEAR.

A. Company witness Jason Sparks discusses uncollectible accounts expense beginning on page 20 of his direct testimony and also sponsors Exhibit A-13, Schedule C5.6. The Company started its calculation of the uncollectible expense of $50.9 million for the projected test year by using three years of net write-offs of bad debts to revenues from 2020, 2021, and 2022. Based on the average ratio of 0.78% of net write-offs to revenues for the three years ending in 2022, the Company applied the ratio to projected revenues of $6.311 billion, to calculate an uncollectible account expense of $49.1 million. However, to this result, he added an additional $1.8 million of net write-offs charged directly to other expenses than bad debts expense and increased the total expense to $50.9 million.

Q. WHAT APPROACH DO YOU PROPOSE TO SET UNCOLLECTIBLE ACCOUNTS EXPENSE FOR THE PROJECTED TEST YEAR?

My approach is similar to the Company's, except that I incorporated results for the three years ended 2023 into my analysis based on information received from the Company for 2023.[73] I used the Commission-approved methodology of a three-year average of charge-

[73] DR AGDE-1.27a attachment.

offs to revenues. The Commission has stated in several cases that the use of a three-year average ratio of charge-offs to revenues applied to future revenue is the most appropriate way to forecast uncollectible accounts expense.

Q. WHAT IS YOUR PROJECTED AMOUNT FOR UNCOLLECTIBLE ACCOUNTS EXPENSE FOR THE PROJECTED TEST YEAR?

For the projected test year, I forecasted uncollectible accounts expense of $47.0 million using the three-year historical ratio of net charge offs to revenue for 2021, 2022, and 2023. Exhibit AG-41 shows the net charge-offs for the three-year period of $40.0 million for 2021, $37.7 million for 2022, and $44.1 million for 2023.

Line 4 of the exhibit shows the average percentage of 0.716% as the ratio of net charge-offs to revenue for the three-year historical period. This percentage is multiplied by the projected test year revenues of $6.399 billion on line 5 to derive the forecasted amount of uncollectible accounts expense of $45.8 million on line 6. To this amount, I added average amounts charged directly to other accounts of $1.2 million, which results in a $47.0 million expense forecast for the projected test year. This amount is lower than the Company's forecast by $3.8 million.

Therefore, the Commission should set the uncollectible accounts expense for the projected test year at $47.0 million and reduce the Company's forecasted O&M expense by $3.8 million.

G. Injuries and Damages

Q. THE COMPANY FORECASTED $18.4 MILLION FOR INJURIES AND DAMAGES FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS AMOUNT?

A. No. On page 3 of Exhibit A-13, Schedule C5.10, the Company developed its forecasted expense for injuries and damages by using the actual expense for the five years ending 2022. This information is now stale. Based upon more recent information available from the Company, I updated the five-year average to incorporate 2023.[74]

Exhibit AG-42 shows the updated calculation for injuries and damages expense. During the past five years the injuries and damages expense has ranged from $5.0 million to $33.0 million. Therefore, the use of the five-year average is a reasonable approach to set the amount of expense for the projected test year given the variability in annual expenses. This methodology has previously been accepted by the Commission.

Based on the most recent five years of actual expenses, I calculated an average expense of $15.577 million. This amount is lower by $2.863 million than the Company's forecast of $18.440 million. Therefore, I recommend that the Commission adopt an Injuries and Damages expense amount of $15.557 million for the projected test year and reduce the Company's forecasted O&M expense by $2.863 million.

[74] DR AGDE-1.38 Attachment.

H. Active Employee Health Care Expense

Q. IN EXHIBIT A-13, SCHEDULE C5.11, THE COMPANY FORECASTED THE ACTIVE EMPLOYEE HEALTH CARE EXPENSE (MEDICAL, DENTAL, AND VISION) AT $56.1 MILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS AMOUNT?

A. No. The Company's forecasted Active Health Care expense forecast of $56.1 million for the projected test year is an increase of $7.2 million, or 15%, over the adjusted amount of $48.9 million in 2022. There are at least two major problems with the Company's active health care expense projection and the approach taken to forecast the expense. First, the Company continues to apply inflationary factors to historical costs, which it misnames as constant dollar averaging and as a normalization adjustment. This is simply a process that increases actual historical costs in a way that is divorced from reality. This approach has been repeatedly rejected by the Commission, but the Company continues to propose it rate case after rate case.

Second, he uses national health care cost trend rates of 7.0% to 7.5% adjusted down to cost increase rates of 4.0% to 5.1% to forecast future health care costs, instead of using historical health care cost increases actually experienced by the Company. The combination of these factors unnecessarily inflates the forecasted expense for the projected test year.

Q. HAVE YOU CALCULATED A MORE APPROPRIATE EXPENSE FOR HEALTH CARE FOR THE PROJECTED TEST YEAR?

A. Yes. In Exhibit AG-43, I calculated a forecasted expense of $52.9 million for the projected test year. To arrive at this amount, I used information obtained from Exhibit A-13, Schedule C5.11.3, which has the actual average cost of health care per employee from 2017 to 2022 without the constant dollar averaging adjustments.

From the 2017 to 2022 data, I calculated the average rate of increase in healthcare costs of 3.33%. Using this annual rate of increase and applying it to the latest actual costs from 2023, I calculated the projected test year expense of $52.9 million. This expense amount excludes the portion of health care costs that are capitalized. The $52.9 million is a reasonable forecast of health care expenses for the projected test year based on actual cost trends, in contrast with the Company's artificially derived expense of $56.1 million.

I recommend that the Commission approve the $52.9 million of forecasted active health care expense for the test year and remove $3.2 million from the Company's forecasted O&M expense in this case.

I. Supplemental Savings Plan

Q. THE COMPANY HAS INCLUDED $3.2 MILLION OF EXPENSE FOR ITS SUPPLEMENTAL SAVINGS PLAN ON EXHIBIT A-13, SCHEDULE C5.11.

SHOULD THE COMMISSION ACCEPT THIS EXPENSE IN SETTING CUSTOMER RATES?

A. No. Company witness Matthew Fix explains on page 13 of his direct testimony that the Supplemental Savings Plan is for Company employees at the Director level and above, whose contributions to tax qualified benefits is limited due to IRS regulations.

This benefit plan is for a very limited number of highly-paid employees. Customers should not pay for costs that benefit only a select few employees by including these costs in forecasted O&M expense. This plan is similar to the expense for the Supplemental Employee Retirement Plan (SERP), which the Commission has previously rejected.

Therefore, I recommend that the Commission remove the $3.2 million for the Supplemental Savings Plan from the Company's forecasted O&M expense.

J. Private Corporate Jet Travel Costs

Q. PLEASE DISCUSS THE INCLUSION OF CORPORATE JET TRAVEL COSTS IN O&M EXPENSES FOR THE PROJECTED TEST YEAR.

A. In discovery, the Attorney General asked the Company to report the cost and use of privately hired corporate jet aircraft by Company employees or employees of the parent company and affiliates who bill the Company for reimbursement of those costs. In response, the Company reported that it leases a fractional share of an aircraft for use by executives at the Vice President level and above for business travel.

The information provided by the Company shows that several executives of the Company, DTE Gas, and DTE Energy, along with certain members of DTE's Board of Directors took 16 trips on the corporate leased aircraft in 2022 to investor and security analyst meetings and conferences, as well as to out of state Board of Directors meetings. The portion of the cost billed to the Company in 2022 was $236,299 and in 2023 was $139,026. In the discovery response the Company stated that $258,000 of expense was included in the projected test year in this rate case.[75]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission disallow recovery of costs for privately-hired corporate jet use, particularly since the travel pertains to investor and board of director matters that do not directly benefit customers but instead may benefit shareholders. Although commercial flights may be less convenient, they are less costly and less impactful on the environment relative to the emissions of private jets for the few individuals that they carry. In 2020, DTE Energy announced its goal of achieving net zero emissions by 2050. Private jet travel certainly goes counter to that goal.

Therefore, I recommend that the Commission remove the $258,000 of costs that the Company reported it included in the projected test year.

[75] Exhibit AG-47 includes DR AGDG-1.24.

K. 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 covering the projected test year for the twelve months ending December 2025, the Company seeks to recover $59.5 million of employee incentive payments. Based upon the information provided on page 39 of the direct testimony of Mr. Fix, $8.8 million pertains to the Annual Incentive Plan (AIP), $30.3 million to the Rewarding Employees Plan (REP), and $20.4 million pertains to the Long-Term Incentive Plan (LTIP).

2023 Annual Incentive Plan – for DTE Electric (excluding Nuclear) the AIP is an annual bonus program focused on the following major categories and specific measures:

1. 40% on Financial Performance (DTE Electric Earnings, DTE Electric Cash From Operations, and DTE Energy Earnings per Share).
2. 20% on Customer Satisfaction (MPSC Complaints and Net Promoter Score).
3. 15% on Employee Engagement (DTE Electric Employee Engagement, DTE Electric OSHA Incident Rate, and DTE Energy High Energy or Fatality Rate).
4. 25% on Operating Excellence (SAIDI Excluding MEDS, Nuclear On-Line Reliability Loss, Generation Availability, and Customers Experiencing Multiple Interruptions (CEMI).

The operating measures for the nuclear employees are substantially similar, except that 65% of the weight is based on Operating Excellence, zero weight on Customer Satisfaction, 15% on Safety and Engagement, and only 20% is based on Financial Performance.

These measures described above are for the year 2023. 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.

2023 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 Electric and its affiliates, the REP covers all other employees of these companies.

Both the AIP and REP are also applied to DTE Energy Corporate Services employees providing support services to DTE Electric.

2022 Long Term Incentive Plan – The LTIP for DTE Electric and for DTE Energy Corporate Services employees is an annual performance unit and stock grant plan focused primarily on achieving multi-year goals and specifically on the following measures:

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

For employees in the Company's Nuclear Division, the financial goals are a 20% weighting, and the "on-line Reliability Loss Factor" and "INPO Index" represent 80% of the weighting.

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. In this regard, page 39 of Mr. Fix's testimony shows that $39.2 million out of the $59.5 million of incentive compensation expense requested pertains to the Company's financial metrics. Additionally, the customer benefits presented by the Company are based on a faulty premise of historical cost savings and an expectation that future targets of performance will be achieved.

With regard to the AIP and REP, nearly half of the incentive payout at target level relates to DTE Energy achieving operating 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, since they are based in part on earnings from the gas 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 2023 represents just 20% of the total weighting.

With regard to 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 performance of the departments responsible for those operations, but they have no direct visibility to customers. The only measures that have a direct link to customers are the Electric outage metrics (SAIDI excluding MEDS) and the metrics addressing multiple customer outages, which represent a small portion of the expected payout. Moreover, improvements in this area will be largely a function of a more aggressive tree trimming program and capital spending programs, which are paid for through increases in customer rates.

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, 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 Electric customers and everything to do with creating value for DTE Energy shareholders. Similarly, the other measure, DTE Electric return on equity, is also very removed from any quantifiable benefits that directly accrue to customers. To some degree this last item is actually duplicative of the Operating Earnings and Cash Flow measures included in the AIP and REP plans.

The arguments that some of these measures will create a 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-21, Schedule K6, Mr. Fix included a calculation that purports to show that recent operating and financial cost savings are exceeding adjusted incentive plan payments by $45.0 million. However, the largest benefits showing in this exhibit are in the areas of (1) Safety ($9.5 million); (2) Operating Excellence ($58.4 million), with a large part of this category being highly dependent upon a more aggressive tree trimming program and capital spending program, which should in turn reduce the SAIDI outage metric; and (3) $20.4 million of benefits related to Employee Engagement Gallup results, whereby better employee survey results should (according to Gallup) lead to reduced absenteeism, higher productivity, and a better safety record.

Q. PLEASE COMMENT ON THE COMPANY'S PERFORMANCE ON THE OPERATING METRICS IN 2023.

A. In response to discovery, the Company provided the results of the incentive performance measures for the year 2023. The 2023 results show that DTE Electric's performance on 7 of the 9 metrics was below target. Nuclear Generation's performance measures were below target in 4 of the 8 metrics, and DTE LLC's performance was below target in 7 of the 8 metrics.[76] On average in 2023, target performance was reached for only one-third of the performance metrics.

Q. DO THE 2023 PERFORMANCE LEVELS RAISE UNCERTAINTY WITH RESPECT TO WHAT WILL BE PAID OUT UNDER THE INCENTIVE PLANS DURING THE PROJECTED TEST YEAR PERIOD?

A. Yes. Mr. Fix stated on page 39 of his testimony that the $59.5 million of incentive compensation expense is based on "Target" performance levels. Therefore, if the Company's sub-standard performance levels continue into the projected test period, then a substantial portion of the incentive payments anticipated by Mr. Fix will not happen.

As shown in Exhibit AG-21, the Company has not been able to meet 100% of the operating performance targets in the past five years. Accordingly, 2023 was not a one-year anomaly. Mr. Fix's testimony and exhibits provide little assurance that all operating performance

[76] Exhibit AG-21 includes DR AGDE-1.48 with attachment.

measures can be achieved at 100% of target level in the future with any consistency, as he has assumed in calculating the incentive compensation expense that the Company seeks to recover in this case.

In summary, my assessment is that the Company has failed to show that it has achieved consistent performance at target levels to justify recovery of 100% of incentive pay expenses relating to the operating performance measures.

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

A. On page 39 of his direct testimony, Mr. Fix has included a table showing the components of the incentive compensation expense that the Company has included in the O&M expense for the projected test year. For the reasons described above, I recommend that the Commission remove the entire $39.2 million related to financial performance measures.

With regard to the portion of incentive compensation relating to operating measures, my initial instinct is to also disallow this portion in its entirety, as I have recommended in several 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 has in recent cases allowed recovery of a portion of the short-term incentive pay related to operating performance measures for DTEE and Consumers Energy. In that vein, I recommend that the Commission allow recovery of a portion of incentive compensation expense pertaining to operating performance measures.

In DR AGDE-1.48, included in Exhibit AG-21, the Company calculated the percentage of non-financial metrics achieved at target or better over the past five years ending in 2023. The overall percentage achieved by the three organizations over the five-year period is approximately 47.4%. The total amount of incentive compensation calculated by the Company at target for operating measures relating to the incentive compensation plans is $20,271,000, as shown in Table 3, on page 39 of Mr. Fix's direct testimony. Therefore, I recommend that the Commission only approve recovery of incentive compensation expense for 47.4% of the $20,271,000, or $9,608,000, and disallow recovery of the remaining $10,663,000 for the operational metrics. This amount, plus the $39,232,000 disallowance related to financial metrics, results in a total disallowance of $49,895,000 of the $59.5 million of incentive compensation expense proposed by the Company in this case. In addition, as discussed in the Working Capital section of my testimony and shown in Exhibits AG-20 and AG-44, the Commission needs to remove $1,358,000 of negative amortization expense from excess compensation expense paid in the 2023 projected test year in Case No. U-20836. Therefore, the total reduction in incentive compensation expense is $51,253,000.

L. O&M Expense Summary

Q. WHAT ARE THE TOTAL ADJUSTMENTS THAT YOU RECOMMEND TO THE COMPANY'S FORECASTED O&M EXPENSES?

A. I recommend total reductions to O&M expenses of $123.5 million as discussed above. Exhibit AG-20 and the table below provide a summary of the areas where I proposed O&M expense adjustments.

Summary of O&M Expense Reductions	Amount ($Millions)
Inflation Adjustments	$ 14.6
Steam Generation Expense	21.9
Voluntary Separation Program	10.1
Tree Trimming Surge Savings	8.8
Merchant Credit Card Fees	3.5
Uncollectible Accounts Expense	3.8
Injuries & Damages Expense	2.9
Active Health Care	3.1
Supplemental Savings Plan	3.2
Corporate Aircraft	0.3
Employee Incentive Compensation	51.3
Total Reduction	**$123.5**

VIII. 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 $40,788,000. The calculation of this amount is shown in Exhibit AG-18 and is based on the same depreciation rates used by the Company on page 2 of Exhibit A-13, Schedule C6.

I recommend that the Commission reduce the depreciation expense proposed by the Company for the projected test year by $40,788,000.

IX. 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 $12,261,000. I recommend that the Commission reduce the Company's property tax expense by this amount for the projected test year.

X. Adjustments To Revenue Deficiency

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

A. Exhibit AG-48 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $139.5 million, which is a reduction of $316.9 million from the Company's requested level of $456.4 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $139.5 million.

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 to oversee 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 to ensure 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.

Subsequent to 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.

Experience and Qualifications of Sebastian Coppola

SEMCO 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 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 Michigan Gas Utilities Corporation (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 Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
  - Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (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.

Experience and Qualifications of Sebastian Coppola

- 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 DTE Electric Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (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 Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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
- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.

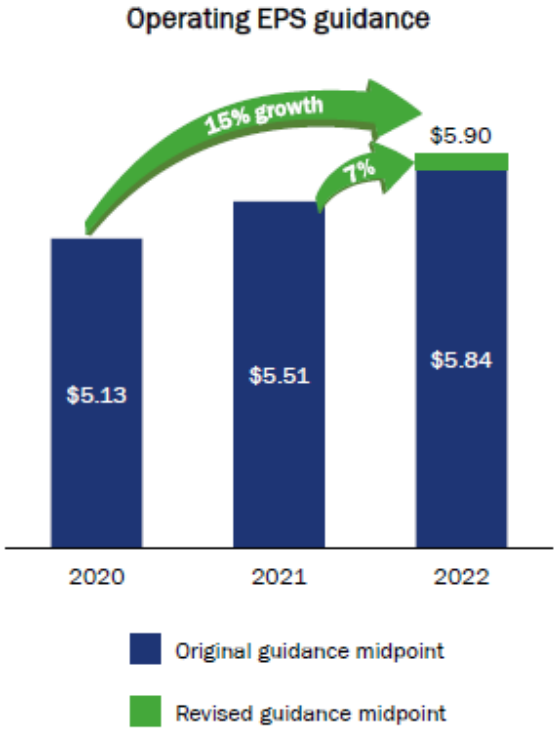
EDUCATIONAL BACKGROUND

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.


DTE ENERGY
BUSINESS UPDATE
MARCH 8, 2022
DTE

Delivered strong financial results in 2021 and well-positioned for growth in 2022 and beyond

- ✓ Strong 2021 operating EPS[1] exceeded high end of guidance
- ✓ Successful spin of DTM
- ✓ Raised 2022 operating EPS guidance range to $5.80 - $6.00; revised guidance midpoint of $5.90 per share provides 7% growth from 2021 original guidance midpoint
- ✓ Reaffirming 5% - 7% operating EPS growth through 2026
- ✓ 7% dividend growth extended to 2022, consistent with high end of operating EPS growth target
- ✓ Utility 5-year capital investment is $1 billion higher than previous plan; over $40 billion investment plan over the 10-year period
- ✓ Strategic focus on decarbonization at DTE Vantage supporting a cleaner economy



DTE

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

DTE Electric: transformational investments in generation and distribution provide customers cleaner, more reliable energy

Achieved operational successes in 2021

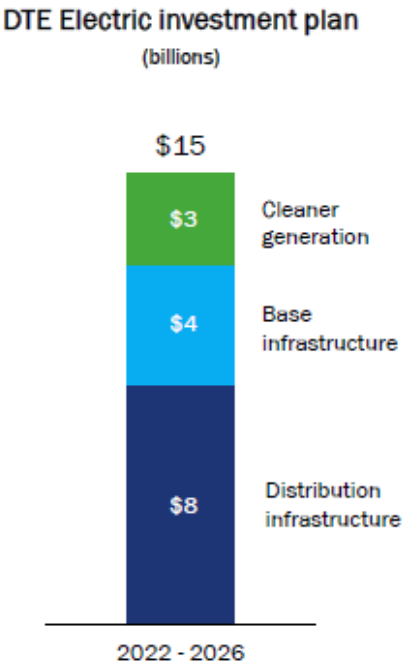
- Announced accelerated carbon reduction plan
  - Ceasing coal use at Belle River Power Plant and reducing carbon emissions by 50% by 2028, two years earlier than originally planned
- Expanded voluntary renewables program, one of the largest in the nation
- Began testing phase at Blue Water Energy Center

Focusing on the grid of the future and continued decarbonization efforts

- Filing updated IRP in October, one year earlier than planned
- Evaluating the opportunity to exit coal use at Monroe Power Plant earlier than 2040
- Investing in the grid of the future to ensure best-in-class performance

Maintaining affordability while modernizing the grid and improving reliability

- Filed first general rate case at DTE Electric in almost 3 years
- Implemented innovative regulatory strategies to keep base rates flat



DTE

Building the grid of the future and clean energy transformation creates $35 billion of investment opportunity over the next 10 years

Robust investment opportunities for the grid of the future to improve reliability and provide additional capacity

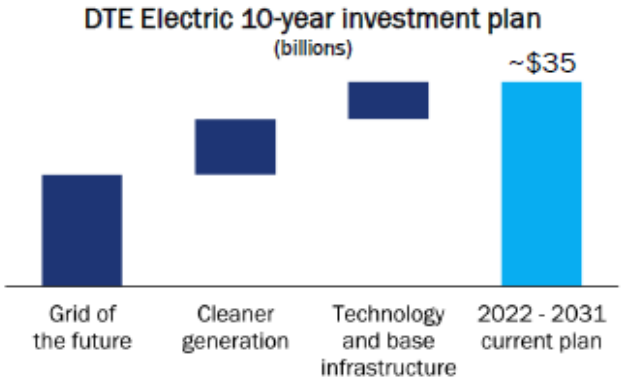
- Hardening the system with circuit rebuilds, new poles, cables and transformers
- Rebuilding sub-transmission and substations for increased capacity and reliability
- Technology and automation driving down outages and their duration

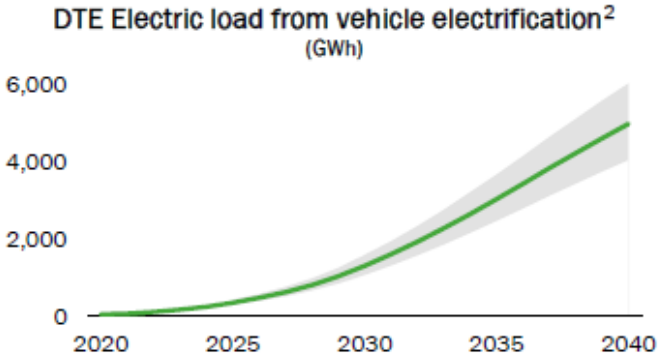
Accelerating the cessation of coal use drives replacement investment

- Renewable resources, short and long duration storage, demand response and dispatchable resources[1]

Preparing for increased pace of electric vehicle adoption that drives load growth and the need for additional grid reliability investment

- General Motors recently announced a $7 billion investment that secures its commitment to accelerate an all-electric future
  - Includes a $4 billion investment in our service territory to convert GM's Orion Township assembly plant to produce full-size electric pick-up trucks



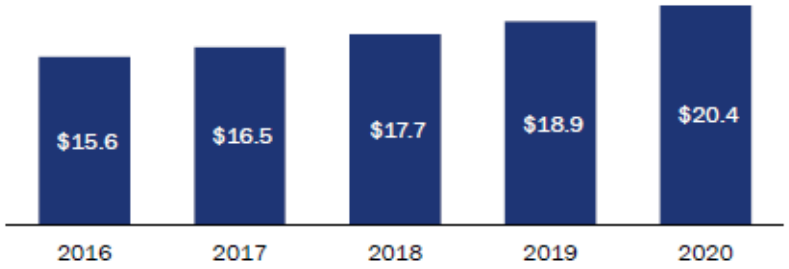


DTE

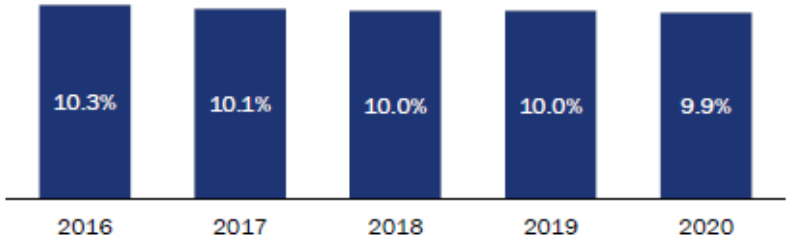
1. Examples include combined cycle plant with carbon capture and storage and hydrogen
2. Excludes underlying macroeconomic conditions including energy efficiency programs

Utilities have provided solid rate base growth

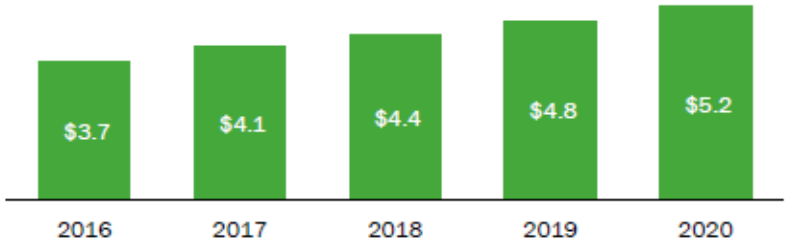
DTE Electric rate base[1]
(billions)



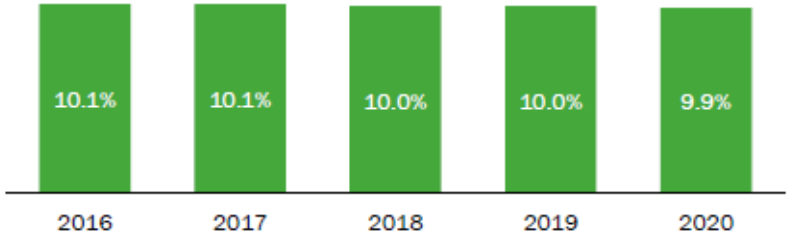
DTE Electric authorized ROE



DTE Gas rate base[1]
(billions)



DTE Gas authorized ROE



DTE

1. Year-end balances; Electric rate base includes renewables investment

Blue Chip Financial Forecasts®

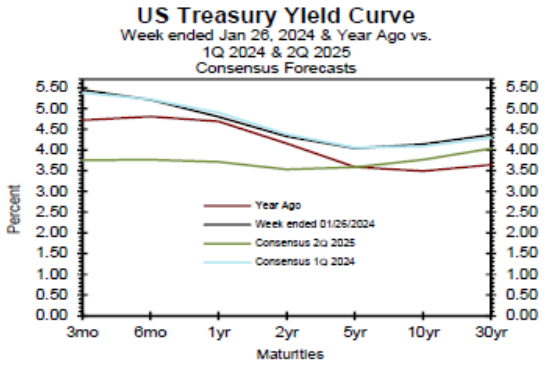
Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

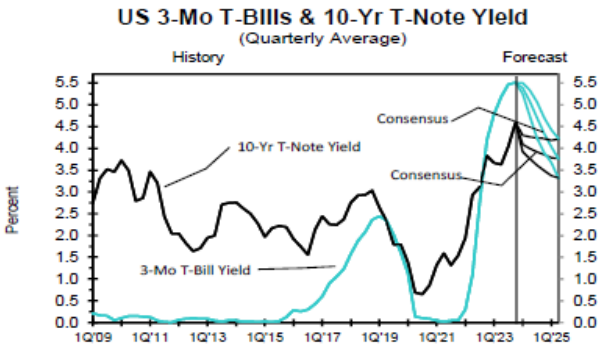
Vol. 43, No. 2, February 1, 2024

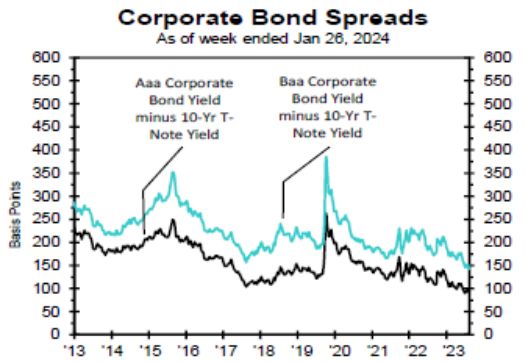
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

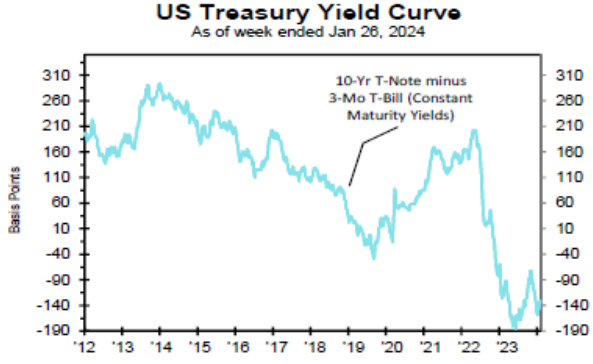
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	1Q	2Q	3Q	4Q	1Q	2Q
Interest Rates	Jan 26	Jan 19	Jan 12	Jan 6	Dec	Nov	Oct	4Q 2023	2024	2024	2024	2024	2025	2025
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.3	5.1	4.7	4.4	4.1	3.8
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.5	8.2	7.9	7.6	7.3	7.0
SOFR	5.31	5.31	5.31	5.36	5.33	5.32	5.31	5.32	5.3	5.2	4.8	4.5	4.2	3.9
Commercial Paper, 1-mo.	5.32	5.33	5.32	5.32	5.32	5.33	5.33	5.33	5.3	5.1	4.7	4.4	4.1	3.9
Treasury bill, 3-mo.	5.45	5.46	5.47	5.47	5.44	5.52	5.60	5.52	5.4	5.1	4.7	4.3	4.0	3.8
Treasury bill, 6-mo.	5.21	5.20	5.22	5.25	5.34	5.44	5.57	5.45	5.2	5.0	4.6	4.3	4.0	3.8
Treasury bill, 1 yr.	4.80	4.79	4.77	4.83	4.96	5.28	5.42	5.22	4.9	4.7	4.4	4.1	3.9	3.7
Treasury note, 2 yr.	4.33	4.32	4.30	4.36	4.46	4.88	5.07	4.80	4.4	4.2	4.0	3.8	3.7	3.5
Treasury note, 5 yr.	4.04	4.02	3.93	3.96	4.00	4.49	4.77	4.42	4.1	3.9	3.8	3.7	3.6	3.6
Treasury note, 10 yr.	4.14	4.12	4.00	3.98	4.02	4.50	4.80	4.44	4.1	4.0	3.9	3.9	3.8	3.8
Treasury note, 30 yr.	4.37	4.34	4.19	4.12	4.14	4.66	4.95	4.58	4.3	4.2	4.2	4.1	4.0	4.0
Corporate Aaa bond	5.07	5.04	4.98	4.97	4.95	5.52	5.87	5.45	5.0	5.0	4.9	4.9	4.8	4.8
Corporate Baa bond	5.57	5.55	5.50	5.51	5.51	6.15	6.53	6.07	6.0	6.0	5.9	5.9	5.8	5.8
State & Local bonds	4.17	4.10	4.05	4.03	4.13	4.56	4.88	4.52	4.3	4.3	4.2	4.2	4.1	4.1
Home mortgage rate	6.69	6.60	6.66	6.62	6.82	7.44	7.62	7.29	6.7	6.6	6.5	6.3	6.2	6.1
	History								Consensus Forecasts-Quarterly					
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q
Key Assumptions	2022	2022	2022	2022	2023	2023	2023	2023	2024	2024	2024	2024	2025	2025
Fed's AFE $ Index	108.3	113.5	118.8	119.8	115.5	114.6	115.0	116.6	115.2	114.9	114.7	114.5	114.7	114.6
Real GDP	-2.0	-0.6	2.7	2.6	2.2	2.1	4.9	3.3	1.4	0.9	0.9	1.4	1.8	2.0
GDP Price Index	8.5	9.1	4.4	3.9	3.9	1.7	3.3	1.5	2.2	2.2	2.3	2.2	2.2	2.1
Consumer Price Index	9.2	9.7	5.5	4.2	3.8	2.7	3.6	2.8	2.5	2.4	2.4	2.3	2.2	2.2
PCE Price Index	7.7	7.2	4.7	4.1	4.2	2.5	2.6	1.7	2.2	2.3	2.2	2.2	2.1	2.1

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).









MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.96a
Respondent: B. Hill
Page: 1 of 1

Question: 96. Refer to Exhibit A-12, Schedule B5.4, page 3. Please:
a. Provide the source document and specific reference within the document for the inflation rates used for 2019 through 2022.

Answer: Please see file named "U-21534 Capital Exhibits A-12 B5.4 DO.xlsx" at https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U21534/Documents/Forms/AllItems.aspx?id=%2Fsites%2FDiscoveryPortal%2FElec%2FU21534%2FDocuments%2FInitial%20Filing%20Documents%2F03%20Working%20Models&viewid=c5988175%2D3405%2D40fc%2Db0b8%2Da8fd6e0b646a for all calculations used.

Inflation rates used for historical years were the CPI-U rates which are created and maintained by the U.S. Bureau of Labor and Statistics at https://www.bls.gov.

Inflation rates used:
2019: 1.8%
2020: 1.2%
2021: 4.7%
2022: 8.0%

Attachment: N/A

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.96b
Respondent: B. Hill
Page: 1 of 1

Question: 96. Refer to Exhibit A-12, Schedule B5.4, page 3. Please:
b. Expand the schedule to show the actual capital expenditures for 2023 for each line item.

Answer: Please see attached file.

Attachment: U-21534 AGDE-3.96b-01 A-12 B5.4 Base Capital 2018-2023

U-21534 AGDE-3.96b-01 A-12 B5.4 Base Capital 2018-2023

Michigan Public Service Commission — Case No.: U-21534
DTE Electric Company — Exhibit: A-12
Projected Capital Expenditures — Schedule: B5.4
Distribution Plant - Emergent Replacements — Witness: B. L. Hill
($000) — Page: 3 of 26

	(a)		(b)	(c)	(d)	(e)	(f)	(g)		(h)	(i)	(j)
			Capital Expenditures									
			Historical	Historical	Historical	Historical	Historical	Historical	Historical	1/1/2025 -	1/1/2022 -	Emergent
Line			12 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	5-year	12 mos. ended	12/31/2025	12/31/2022	Replacements
No.	Description		12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	average	12/31/2023	Test Year	Historical	Adjustment
								1/				(h) - (i)
1	**Base Capital Programs**											
2	**Emergent Replacements**											
3	**Storm**		142,108	178,931	150,897	395,286	181,326	209,710	273,541			
4	Inflation Adjustment		23,437	25,825	19,731	31,623	-	20,123	-			
5	Inflation Adjusted Historical Capital		165,545	204,756	170,628	426,909	181,326	229,833	181,326	229,833	181,326	48,507
6	Inflation 1/1/23 -12/31/23	3.20%								7,355	5,802	1,552
7	Inflation 1/1/24 -12/31/24	2.90%								6,878	5,427	1,452
8	Inflation 1/1/25 -12/31/25	2.90%								7,078	5,584	1,494
9	Projected Storm Replacements									251,144	198,139	53,005
10	**Non-Storm**		159,555	163,112	155,324	209,236	263,014	190,048	209,356			
11	Inflation Adjustment		26,315	23,542	20,310	16,739	-	17,381	-			
12	Inflation Adjusted Historical Capital		185,870	186,654	175,634	225,975	263,014	207,429	263,014	207,429	263,014	(55,585)
13	Inflation 1/1/23 -12/31/23	3.20%								6,638	8,416	(1,779)
14	Inflation 1/1/24 -12/31/24	2.90%								6,208	7,871	(1,664)
15	Inflation 1/1/25 -12/31/25	2.90%								6,388	8,100	(1,712)
16	Projected Non-Storm Replacements									226,663	287,402	(60,739)
17	**Substation Reactive**		44,275	40,386	38,131	46,008	40,382	41,837	41,178			
18	Inflation Adjustment		7,302	5,829	4,986	3,681	-	4,360	-			
19	Inflation Adjusted Historical Capital		51,577	46,215	43,118	49,689	40,382	46,196	40,382	46,196	40,382	5,814
20	Inflation 1/1/23 -12/31/23	3.20%								1,478	1,292	186
21	Inflation 1/1/24 -12/31/24	2.90%								1,383	1,209	174
22	Inflation 1/1/25 -12/31/25	2.90%								1,423	1,244	179
23	Projected Substation Reactive Replacements									50,480	44,126	6,353
24	**Total Emergent Replacements Normalization Adjustment (Line 5 + Line 12 + Line 19) Pre-inflation**									483,459	484,722	(1,263)
25	Inflation 1/1/23 -12/31/23	3.20%								15,471	15,511	(40)
26	Inflation 1/1/24 -12/31/24	2.90%								14,469	14,507	(38)
27	Inflation 1/1/25 -12/31/25	2.90%								14,889	14,927	(39)
28	Total Projected Emergent Replacements Expense (Line 9 + Line 16 + Line 23)									528,287	529,667	(1,381)
29	Test Year Emergent Replacement Reduction Based on Strategic Spend									(21,436)		
30	Total Projected Emergent Replacements Expense less Test Year Emergent Reduction based upon Strategic Spend									506,851		

Exhibit AG-4

CONFIDENTIAL

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.117
Respondent: M. Leuker
Page: 1 of 1

Question: 117. Refer to pages 5 and 6 of Mr. Leuker's direct testimony on Economic Outlook. Please provide the number of housing starts in Michigan for 2022 and 2023, and the most recent number forecasted for 2024 and 2025. Identify the source of the information and provide a copy of the source documents showing the as of date of the forecasted information.

Answer: Michigan housing starts are not mentioned in pages 5 and 6 of my direct testimony and are not used in the sales forecast. Please see attachment "U-21534 AGDE-3.117 Michigan Housing Starts".

Attachment: *U-21534 AGDE-3.117 Michigan Housing Starts*

DTE Electric Company
Housing Starts

Case No.: U-21534
Attachment: U-21534 AGDE-3.117 Michigan Housing Starts
Respondent: M.B. Leuker
Page: 1 of 1

June 2024 Long Term

Next Update: July 2024

MI

		2022	2023	2024	2025
Housing Starts, Total Private (Thousands, SAAR)	2024Q1	20.52	19.28	18.54	20.55

Data compiled June 18, 2024.
SAAR = seasonally adjusted annual rate.
Dates in Column B represent the historical end dates of each series
Source: S&P Global Market Intelligence.

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.91b
Respondent: B. Hill
Page: 1 of 1

Question: 91. Refer to lines 4-14 on page 23 of Mr. Hill's direct testimony on the I-375 electric facilities' relocation project. Please:

b. Provide the timeline for each development phase of the project and identify the phase that the project is currently in (i.e., Initial scoping, conceptual analysis, engineering design, out for bid, construction, completed). If the project is being completed in multiples stages, provide the requested information for each stage.

Answer: **Phase 1 – Relocations:**
Initial scoping is complete
Conceptual analysis is complete
Engineering and design: Q2 2023 – Q2 2025 (Current Phase)
Conduit work out for bid: Q2 2024 (Current Phase)
Conduit and cable construction: Q3 2024 – Q4 2025

Phase 2 – New Infrastructure:
Initial scoping: Q4 2024
Conceptual analysis: Q3 2025
Engineering and design: Q3 2025 – Q1 2026
Conduit out for bid: TBD pending MDOT schedule
Conduit and cable construction: TBD pending MDOT schedule

Please note that the Company is awaiting an MDOT schedule for the phase 2 work required and cannot perform the second phase work until MDOT has completed their work.

Attachment: N/A

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.91e
Respondent: B. Hill
Page: 1 of 1

Question: 91. Refer to lines 4-14 on page 23 of Mr. Hill's direct testimony on the I-375 electric facilities' relocation project. Please:

e. Provide the latest project schedule issued by MDOT with project start and completion date, and showing the date when utilities relocation needs to be completed. Provide the as of date of the MDOT schedule.

Answer: The Company has not received a schedule from MDOT at this time and has only received a notice to vacate.

Attachment: N/A

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-4.167
Respondent: R. Steudle
Page: 1 of 1

Question: 167. Refer to the request and response to AGDE-4.120 in Case No. U-21297. Please provide the same information for 2024 and 2025.

Answer:

Estimated Tree-related Annual Cost savings ($ millions)			
Cost Category		2024	2025
Tree-Related O&M	Tree Trim Reactive	8.9	7.4
	Tree Trim Storm	11.2	10
	Other DO – Service Operations Storm and Trouble	8.5	7.5
Tree-Related Capital	Tree Trim Reactive	2.1	1.9
	Tree Trim Storm	12.8	11.4
	Other DO – Service Operations Storm and Trouble	52.0	46.3

Attachment: *NA*

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.107
Respondent: M. Guillaumin
Page: 1 of 1

Question: 107. Refer to Exhibit A-12, Schedule B5.1, page 1, on power generation projects. Please expand this schedule to include the same actual information for each year 2018 to 2023 and provide it in Excel.

Answer: Please see attachment labelled "U-21534 AGDE-3.107 Ex A-12 Sch B5.1 p1 2018-2023".

Attachment: U-21534 AGDE-3.107 Ex A-12 Sch B5.1 p1 2018-2023

Michigan Public Service Commission						Case No.:	U-21534
DTE Electric Company						Question No.:	AGDE-3.107
Actual Capital Expenditures						Witness:	M. Guillaumin
Steam, Hydraulic, and							
Other Power Generation							
($000)							
Line							
No.	Description	2018	2019	2020	2021	2022	2023
1	**Steam Power Generation**						
2	Routine	165,386	198,573	182,121	190,750	218,988	213,273
3	Non-Routine	18,984	59,353	47,451	128,195	104,057	157,175
4	Total Steam Power Generation	184,370	257,926	229,572	318,945	323,045	370,448
5	**Hydraulic Power Generation**						
6	Routine	2,758	4,564	7,736	20,832	12,978	10,144
7	Non-Routine	33,770	34,036	7,882	5,564	9,979	1,508
8	Total Hydraulic Power Generation	36,528	38,600	15,618	26,396	22,957	11,652
9	**Other Power Generation**						
10	Routine	34,293	34,727	11,610	57,616	66,684	47,016
11	Non-Routine	115,376	356,267	379,729	121,616	46,703	21,132
12	Total Other Power Generation	149,669	390,994	391,339	179,232	113,387	68,147
13	Grand Total Capital Expenditures	370,567	687,520	636,529	524,573	459,389	450,247

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.111
Respondent: M. Guillaumin
Page: 1 of 1

Question: 111. Refer to Exhibit A-12, Schedule B5.1, page 3, on power generation. Please expand this schedule to include the same actual information for each year 2018 to 2023 and provide it in Excel.

Answer: Please see attachment labelled "U-21534 AGDE-3.111 Ex A-12 Sch B5.1 p3 2018-2023".

Attachment: U-21534 AGDE-3.111 Ex A-12 Sch B5.1 p3 2018-2023

Michigan Public Service Commission						Case No.:	U-21534
DTE Electric Company						Question No.:	AGDE-3.111
Actual Capital Expenditures						Witness:	M. Guillaumin
Steam, Hydraulic, and							
Other Power Generation -- Routine							
($000)							
Line							
No.	**Total Capital - Routine**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	DATA BY SITE						
1	Fleet Support Services	2,335	1,786	2,320	2,157	3,085	2,201
2	Greenwood	2,617	4,043	13,144	9,269	10,581	10,126
3	Belle River/Range Road	12,991	46,511	47,370	41,366	59,478	32,984
4	St. Clair	18,666	8,963	7,737	2,021	(2)	-
5	Trenton Channel/Sibley Quarry	11,085	3,891	2,458	2,676	614	9,062
6	Monroe	117,692	133,379	109,092	133,262	145,233	158,899
7	Ludington	2,758	4,564	7,736	20,832	12,978	10,144
8	Peakers	34,293	34,727	11,610	56,852	65,649	44,372
9	Blue Water	-	-	-	764	1,035	2,644

Exhibit AG-9

CONFIDENTIAL

Exhibit AG-10

CONFIDENTIAL

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.102a
Respondent: J. Davis
Page: 1 of 1

Question: 102. Refer to Exhibit A-12, Schedule B5.3, page 1. Please:
a. Expand this schedule to include the same actual information for each year 2018 to 2023.

Answer: Please find the attached for the Nuclear Generation capital expenditures summary (Exhibit A-12, Schedule B5.3, page 1) for the actual historical 12-month periods ending December 31, 2018, 2019, 2020, 2021, 2022 and 2023, the projected 12-month bridge period ending December 31, 2024, and the projected 12-month test period ending December 31, 2025.

Attachment: U-21534 AGDE-3.102a-01 NG A12B53P1_2018-2023.pdf

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Nuclear Production Plant & Nuclear Fuel
($000)

MPSC Case No.: U-21534
Respondent: J. C. Davis
Requester: Attorney General
Question No.: AGDE-3.102a
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Capital Expenditures								
		Historical	Historical	Historical	Historical	Historical	Historical			Projected Test Year
Line No.	Description	12 mos. ended 12/31/2018	12 mos. ended 12/31/2019	12 mos. ended 12/31/2020	12 mos. ended 12/31/2021	12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024 col. (g)+(h)	12 mos. ending 12/31/2025
1	**Nuclear Production Plant**									
2	Routine and Small Projects 1/	106,794	45,284	94,044	53,076	91,269	64,822	68,892	133,714	42,450
3	Non-Routine and Large Projects 2/	61,112	84,784	176,456	96,824	173,244	89,201	113,872	203,073	39,420
4	Total Projects	167,906	130,068	271,300	149,700	264,513	154,022	182,765	336,787	80,870
5	**Nuclear Fuel**									
6	Uranium	28,819	30,578	-	51,761	-	48,048	-	48,048	61,379
7	Conversion	-	-	-	-	-	-	-	-	-
8	Enrichment	25,089	27,317	-	36,292	-	32,989	-	32,989	36,219
9	Fabrication	18,520	20,427	278	32,059	3,246	28,970	2,000	30,970	35,478
10	Total Nuclear Fuel	72,428	78,322	278	120,112	3,246	110,008	2,000	112,008	135,077
11	**Total Capital Expenditures**	240,334	208,390	271,578	269,812	267,759	264,030	184,765	448,795	215,947

1/ See Exhibit A-12, Schedule B5.3, Pages 2 and 3
2/ See Exhibit A-12, Schedule B5.3, Page 4

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.102b
Respondent: J. Davis
Page: 1 of 1

Question: 102. Refer to Exhibit A-12, Schedule B5.3, page 1. Please:

b. Show how the amounts for Nuclear Fuel on lines 6 to 9 for the projected test year were determined and explain why they increase significantly from 2023.

Answer: The Fermi 2 24-month-cycle equilibrium core reload plan is approximately 240 new nuclear fuel assemblies per refueling outage. However, the Fermi 2 Cycle 23 (2024 – 2026) core design only required 220 new fuel assemblies due to Fermi 2's Cycle 22 (2022 – 2024) operational history. DTE Electric projects the Fermi 2 reactor core will require 244 new nuclear fuel assemblies for core reload in Fermi 2 Refueling Outage 23 (spring 2026) to support Fermi 2 Cycle 24 (2026 – 2028) consistent with the Company's 2024 PSCR Plan U-21425.

DTE Electric determines projected nuclear fuel expenditures using industry-accepted software that is in accordance with applicable sections of Title 18 of the Code of Federal Regulations. The Fermi 2 nuclear fuel expenditures for the 12-month projected test period ending December 31, 2025, are an outcome of a reasonable and prudent analysis of the nuclear fuel cycle components and contract terms applied to the projected Fermi 2 nuclear core design requirements, consistent with the Company's 2024 PSCR Plan U-21425.

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.103a
Respondent: J. Davis
Page: 1 of 1

Question: 103. Refer to Exhibit A-12, Schedule B5.3, pages 2-4. For each project of $3.0 million or greater in 2024 and 2025, please:

a. Describe the project, what is being done, and why it is necessary to undertake this project.

Answer: Part III Supplemental filing requirements Attachment 9, file labelled "U-21534 NG Att 9" provides the scope and rationale for each capital project greater than $1 million in total expenditures. Exhibit A-20, Schedule J2 provides further details regarding scope and rationale for Nuclear Generation Capital Routine and Small Projects. My direct testimony further provides additional narrative details regarding scope and rationale for Nuclear Generation Capital Routine and Small Projects and Nuclear Generation Capital Non-Routine and Large Projects. Individual project design changes were provided in response to ABDE-1.13.

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.103b
Respondent: J. Davis
Page: 1 of 1

Question: 103. Refer to Exhibit A-12, Schedule B5.3, pages 2-4. For each project of $3.0 million or greater in 2024 and 2025, please:

b. Provide the project phases of development with related timeline and the identify the current phase of development (i.e., needs identification, initial concept scoping, engineering design, out for bids, construction, completed) and the target in-service date.

Answer: Nuclear Generation does not status projects as described above and therefore cannot provide project status in the requested manner. Target in-service dates for each project are provided in Exhibit A-12, Schedule B5.3, pages 2-4 in Column (g) of each page. As I stated in my direct testimony, most Nuclear Generation capital expenditures in 2024 were to support project implementation during Fermi 2 Refueling Outage 22, which completed in May 2024. Updated capital expenditure forecasts which incorporated actual RF22 performance were provided in response to STDE-2.15.

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.103c
Respondent: J. Davis
Page: 1 of 1

Question: 103. Refer to Exhibit A-12, Schedule B5.3, pages 2-4. For each project of $3.0 million or greater in 2024 and 2025, please:

c. Provide the project cost by year from inception to completion.

Answer: Please find attached the Nuclear Generation actual Routine and Small Project capital expenditures for the historical 12-month periods ending December 31, 2017, 2018, 2019, 2020, 2021, 2022 and 2023 and the projected capital expenditures for the 12-month bridge period ending December 31, 2024, and the 12-month projected test period ending December 31, 2025 in the format of Exhibit A-12, Schedule B5.2 pages 2 - 3.

In the same attachment is the Nuclear Generation actual Non-Routine and Small Project capital expenditures for the historical 12-month periods ending December 31, 2017, 2018, 2019, 2020, 2021, 2022 and 2023 and the projected capital expenditures for the 12-month bridge period ending December 31, 2024, the 12-month projected test period ending December 31, 2025, and the 12-month, beyond-the-test-period period ending December 31, 2026 in the format of Exhibit A-12, Schedule B5.2 page 4.

Attachment: U-21534 AGDE-3.103c-01 ExhibitA-12ScheduleB53 Page 2-4 extended.pdf
U-21534 AGDE-3.103c-02ExhibitA-12ScheduleB53 Page 2-4 extended.xslx

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Nuclear Production Plant
Routine and Small Projects
($000)

MPSC Case No.: U-21534
Respondant: J. C. Davis
Requester: Attorney General
Question No.: AGDE-3.103c
Page: 1 of 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(l)	(m)
							Capital Expenditures					
		Historical	Historical	Historical	Historical	Historical	Historical	Historical	Projected Bridge Period		Projected Test Year	
Line No.	Project Name	12 mos. ended 12/31/2017	12 mos. ended 12/31/2018	12 mos. ended 12/31/2019	12 mos. ended 12/31/2020	12 mos. ended 12/31/2021	12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	In Service Year
										col. (h)+(i)		
1	**Routine and Small Projects**											
2	Undervessel replacements	7,365	5,021	171	11,573	2,502	8,011	212	6,415	6,627	-	Annual
3	Visual Annunciator System (VAS) replacement	10	47	3,315	3,350	3,183	7,570	25	-	25	-	Annual
4	Security system computer	-	-	188	(14)	1,230	7,080	17,011	9,197	26,207	-	Annual
5	Plant radio system	4,390	2,118	2,706	391	2,295	4,176	6,049	1,498	7,546	-	Annual
6	Residual heat removal service water outlet valve (F068A/B) replacement	-	-	-	2,008	1,982	3,817	913	3,900	4,812	-	Annual
7	Environmentally Qualified (EQ) seal replacements	-	-	-	321	3,144	3,758	6	-	6	-	Annual
8	Safety relief valves (SRVs)	-	2,509	530	4,678	1,689	3,148	2,219	2,264	4,483	759	Annual
9	Snubbers	2,682	2,711	28	2,742	531	3,002	284	1,401	1,685	32	Annual
10	Low Pressure Turbine (LPT) expansion joints	-	-	-	996	238	2,423	-	-	-	-	Annual
11	Unitized actuators (UAs) replacement	3,720	3,316	1,541	5,786	1,964	2,389	1,210	4,660	5,870	230	Annual
12	Residual Heat Removal (RHR) motors replacement	-	-	-	-	-	2,374	3,609	2,744	6,352	949	Annual
13	High pressure stop and control valves (HPSV/HPCV) replacement	-	2,468	17	(14)	967	2,274	528	4,141	4,670	-	Annual
14	Reactor recirculation system (RRS) replacements	-	-	-	518	8	2,198	(206)	-	(206)	-	Annual
15	Main Steam Isolation Valves (MSIV) replacement	1,499	839	-	2,621	2	2,141	227	906	1,133	-	Annual
16	Low pressure stop and intercept valves (LPSV/LPIV) replacements	-	-	-	(53)	2,294	2,083	352	4,416	4,768	-	Annual
17	Valve replacements	3,782	1,628	1,796	2,525	2,417	2,066	1,060	1,220	2,280	-	Annual
18	Main steam bypass valve (MSBV) replacement	-	-	-	-	506	1,857	-	-	-	-	Annual
19	Core spray line vents	-	-	-	448	742	1,838	753	1,625	2,377	-	Annual
20	Diesel fire pump	-	-	-	-	1,051	1,720	167	-	167	-	Annual
21	Emergency equipment service water (EESW) pump	-	-	-	-	-	1,669	-	-	-	-	Annual
22	Motor operated valves (MOV)	779	4,995	-	11	200	1,619	-	-	-	-	Annual
23	Reactor Protection System (RPS) motor-generator (MG) set replacements	-	-	-	-	713	1,596	315	-	315	176	Annual
24	Emergency Diesel Generator (EDG) cylinder liner replacements	-	-	-	-	-	1,475	-	-	-	-	Annual
25	Flow accelerated corrosion (FAC) program piping insulation	412	318	35	706	-	1,229	76	758	833	-	Annual
26	Owner Controlled Area (OCA) security access control system	-	-	-	-	-	1,158	(609)	-	(609)	-	Annual
27	Residual heat removal service water (RHRSW) pump	-	-	-	837	440	974	-	-	-	-	Annual
28	Control rod drive mechanism (CRDM) replacement	1,222	4,280	3,857	5,132	4,770	916	4,604	603	5,206	4,867	Annual
29	Moisture separator reheater relief valve (MSRRV)	-	-	41	266	352	819	-	-	-	-	Annual

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Nuclear Production Plant
Routine and Small Projects
($000)

MPSC Case No.: U-21534
Respondant: J. C. Davis
Requester: Attorney General
Question No.: AGDE-3.103c
Page: 2 of 3

Line No.	(a) Project Name	(b) Historical 12 mos. ended 12/31/2017	(c) Historical 12 mos. ended 12/31/2018	(d) Historical 12 mos. ended 12/31/2019	(e) Historical 12 mos. ended 12/31/2020	(f) Historical 12 mos. ended 12/31/2021	(g) Historical 12 mos. ended 12/31/2022	(h) Historical 12 mos. ended 12/31/2023	(i) Capital Expenditures Projected Bridge Period 12 mos. ending 12/31/2024	(j) Capital Expenditures Projected Bridge Period 24 mos. ending 12/31/2024 col. (h)+(i)	(l) Projected Test Year 12 mos. ending 12/31/2025	(m)
30	General plant tools	2,155	2,398	3,223	6,175	4,307	688	3,544	2,504	6,048	3,375	Annual
31	Heater Drains Pump (HDP) replacement	-	-	-	-	-	593	13	-	13	-	Annual
32	Condensate pump	76	753	24	692	0	426	402	1,069	1,471	189	Annual
33	Residual Heat Removal (RHR) HVAC hydramotors	530	432	-	205	80	328	283	86	369	45	Annual
34	Breaker replacement	-	-	-	-	-	308	55	269	324	265	Annual
35	Plant wireless	-	-	-	-	-	297	1,908	5,871	7,778	-	Annual
36	Condensate filter demineralizer (CFD) septas	507	325	648	342	133	233	156	363	519	345	Annual
37	Refuel bridge mast	-	-	-	-	1,007	205	-	-	-	-	Annual
38	Refuel Floor monorail replacement	-	-	-	-	-	205	285	370	655	-	Annual
39	Switchyard footer replacement	-	-	-	-	-	194	237	132	369	-	Annual
40	Unitized Actuator shop	-	-	-	-	-	182	1,359	101	1,460	-	Annual
41	Hot machine shop	-	-	-	-	-	178	3,514	267	3,780	-	Annual
42	Contractor time & work tracking system	-	-	-	-	-	158	24	-	24	-	Annual
43	Piping replacements	366	2,208	20	8,753	7	106	3,851	752	4,603	-	Annual
44	Security defensive strategy simulator	-	-	-	-	1,567	106	-	-	-	-	Annual
45	Control rod blade (CRB) replacements	84	2,831	3,212	-	1,905	78	2,526	49	2,576	887	Annual
46	Pump and motor replacements	-	-	-	542	742	34	318	-	318	-	Annual
47	Reverse osmosis system replacement	-	-	-	-	-	21	-	-	-	2,597	Annual
48	Independent Spent Fuel Storage Installation (ISFSI) casks	76	755	1,079	(762)	1,856	2	49	689	738	282	Annual
49	Integrated Plant Computer System (IPCS) replacement	5,883	4,914	3,961	7,566	537	(10)	-	-	-	-	Annual
50	Paperless recorders replacement	-	422	781	1,212	903	(10)	-	131	131	124	Annual
51	Roof replacements	-	-	-	-	-	-	3,385	-	3,385	-	Annual
52	Neutron Monitoring System replacements	-	-	-	-	-	-	2,171	2,683	4,854	-	Annual
53	SCRAM discharge header	-	-	-	-	-	-	671	1,379	2,051	-	Annual
54	Temporary power modifications	-	-	-	-	-	-	493	1,945	2,438	-	Annual
55	Balance of plant (BOP) battery replacement	-	-	-	-	-	-	85	1,228	1,313	-	Annual
56	Reactor feed pump turbine (RFPT) rotor	847	1,392	-	(1)	-	-	167	1,721	1,888	-	Annual
57	Hydrogen seal replacement	-	-	-	-	-	-	124	1,181	1,304	-	Annual
58	Heater Feed Pump (HFP) replacement	-	-	-	-	-	-	-	340	340	-	Annual
59	Natural draft cooling towers	8,031	7,240	3,673	4,306	-	-	(775)	-	(775)	9,515	Annual
60	Document management system enhancements	-	-	-	-	-	-	-	-	-	9,992	Annual
61	Remote monitoring	-	-	-	-	-	-	-	-	-	4,473	Annual
62	Electronic work package system	-	-	-	-	-	-	-	-	-	2,584	Annual
63	GSW Pump House Critical Digital Asset (CDA)	-	-	-	-	-	-	-	-	-	745	Annual
64	Balance of Projects (<$500K)	8,030	2,641	2,495	(285)	5,848	1,568	1,176	14	1,190	16	Annual
65	**Total Routine and Small Projects**	**95,548**	**56,560**	**33,341**	**73,573**	**52,109**	**81,269**	**64,822**	**68,892**	**133,714**	**42,450**	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Nuclear Production Plant
Non-Routine and Large Projects
($000)

MPSC Case No.: U-21534
Respondant: J. C. Davis
Requester: Attorney General
Question No.: AGDE-3.103c
Page: 3 of 3

No.	Project Name	Historical 12 mos. ended 12/31/2014	Historical 12 mos. ended 12/31/2015	Historical 12 mos. ended 12/31/2016	Historical 12 mos. ended 12/31/2017	Historical 12 mos. ended 12/31/2018	Historical 12 mos. ended 12/31/2019	Historical 12 mos. ended 12/31/2020	Historical 12 mos. ended 12/31/2021	Capital Expenditures Historical 12 mos. ended 12/31/2022	Historical 12 mos. ended 12/31/2023	Projected Bridge Period 12 mos. ending 12/31/2024	Projected Bridge Period 24 mos. ending 12/31/2024	Projected Test Year 12 mos. ending 12/31/2025	Beyond Projected Test Year 12 mos. ending 12/31/2026	Beyond Projected Test Year 12 mos. ending 12/31/2027	Beyond Projected Test Year 12 mos. ending 12/31/2028	Beyond Projected Test Year 12 mos. ending 12/31/2029	Beyond Projected Test Year 12 mos. ending 12/31/2030	In Service Year
													col. (k)+(l)							
1	**Non-Routine and Large Projects**																			
2	Main Unit Generator replacement	297	9,402	10,964	10,742	14,100	29,751	26,611	21,349	47,087	33,774	54,025	87,799	14,292	48,431					2026
3	Torus Vent Header	-	-	-	-	-	-	-	9,411	34,135	-	-	-	-						Annual
4	Underground safety-related service water piping	-	409	1,863	1,482	3,512	13,323	7,958	10,191	23,287	10,459	32,543	43,002	-						2024
5	Main Unit Generator rotor replacement	-	-	-	-	-	-	-	8,047	15,948	-	-	-	-						Annual
6	Generator excitation automatic voltage regulator (AVR)	-	-	-	54	633	3,913	1,943	2,378	11,028	14	-	14	-						Annual
7	Transformer #65 and #69 replacements	-	-	-	-	-	-	11,929	10,495	10,439	115	-	115	-		3,988	8,994			Annual
8	License renewal implementation (LRI)	-	-	1,655	2,809	2,685	4,412	4,043	2,863	5,755	7,748	7,554	15,302	729						2025
9	Circulating Water (CW) Discharge Pipe	-	-	-	-	-	-	-	667	5,251	-	-	-	734	9,669					Annual
10	Feed water heaters replacements	-	-	-	-	-	-	1,821	7,661	4,873	7,006	4,014	11,019	4,730	25,682					2026
11	Drywell Coolers #12 and #13	-	-	-	-	-	609	1,775	1,707	3,451	8	-	8	-						Annual
12	Boraflex fuel storage racks	-	-	-	4,534	1,602	2,928	3,954	2,309	3,397	2,924	1,126	4,051	-						2024
13	Radiation monitors	-	-	-	-	-	-	-	135	2,701	4,749	8,439	13,189	2,611						2024
14	Reactor Building Freight Elevator	-	-	-	-	-	-	878	8,596	1,900	2	-	2	-						Annual
15	Transformer replacements	-	-	-	-	-	144	1,307	2,892	1,625	312	-	312	-						Annual
16	Drywell Cooler #8	-	-	-	-	562	611	129	845	1,501	36	-	36	626						2026
17	Fire header restoration	1,538	-	668	-	1,490	1,012	47	84	840	4,093	-	4,093	-						Annual
18	Drywell Coolers #10 and #14	-	-	-	-	-	1,824	2,356	412	33	-	-	-	-						Annual
19	Off-gas chiller replacement	-	-	-	-	327	3,516	9,072	147	15	-	-	-	-						Annual
20	General Service Water (GSW) intake groin replacement	-	-	-	-	81	5,682	(7)	4,526	(18)	17,981	-	17,981	-						2024
21	Turbine Building moisture barrier	-	-	-	-	-	-	-	-	-	507	-	507	-						2024
22	Digital control modifications	-	-	-	-	-	-	-	-	-	209	-	209	-				4,000	8,000	Annual
23	Drywell moisture barrier replacement	-	-	-	-	-	-	-	-	-	66	2,766	2,832	-						2024
24	Fire detection system replacement	-	-	-	-	-	-	-	-	-	13	2,317	2,330	1,252		5,000	5,000			2024
25	Interuptable Air Supply (IAS) dryer replacements	-	-	-	-	-	-	-	-	-	4	825	829	-						Annual
26	Reactor recirculation motor-generator (RRMG) replacements	-	-	-	-	-	-	-	-	-	0	-	0	6,226	10,893	4,107	5,053			2026
27	Turbine controls replacements	-	-	-	-	-	-	-	-	-	37	263	300	762		4,000	4,000	8,000	8,000	Annual
28	Sanitary system replacement	-	-	-	-	-	-	-	-	-	-	-	-	6,457						Annual
29	Emergency Diesel Generator Service Water (EDGSW) piping	-	-	-	629	2,712	814	1,298	150	(4)	-	-	-	-						Annual
30	Other Capital Spend <$100K	-	-	-	570	-	130	-	-	-	(859)	-	(859)	-						Annual
31	**Total Non-Routine and Large Projects**	**1,835**	**9,811**	**15,151**	**20,820**	**27,703**	**68,671**	**75,113**	**94,864**	**173,244**	**89,201**	**113,872**	**203,073**	**38,420**	**94,675**	**17,095**	**23,047**	**12,000**	**16,000**	

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.114a
Respondent: M. Hatsios
Page: 1 of 2

Question: 114. Refer to Exhibit A-12, Schedule B5.7.3 on Customer Service IT projects. For each project of $3.0 million or greater in 2024 and 2025, please:
a. Describe the project, what is being done and why it is necessary to undertake each project.

Answer: The requested information for Customer Service IT projects that are $3.0 million or greater in 2024 and 2025 can be found using the references listed below:

2024-2025 Projects ($3 million or greater)	Witness Hatsios Direct Testimony Pages and Exhibit Reference	Exhibit A-24 N1.1 Reference
MIGP Customer - Requested Renewable Energy Projects	MJH-86 Line 10 - MJH-87 Line 7	Page 1 Line 6 Pages 17 - 19
MIGP Scope 3 Billing and Enrollment	MJH-89 Line 21 - MJH-90 Line 6	Page 1 Line 10 Pages 33-34
Regulatory Compliance	MJH-93 Line 12 - MJH-95 Line 24	Page 2 Line 17 Pages 43-44
Rider 17 – MIGreenPower, Residential and Small Commercial & Industrial	MJH-90 Lines 8 - 22	Page 2 Lines 19-20 Pages 47-50
Advanced Analytics AA Use Cases Implementation	MJH-40 Lines 12-24 and MJH-49 Line 24 - MJH-52 Line 20	Page 2 Line 24 Pages 57-60
Collection Web Self-Service	MJH-22 Lines 14-24and MJH-23 Line 1- MJH 24 Line 17	Page 3 Lines 37-38 Pages 86-89
Error Free Communication - Outage Status (Customer-Facing System)	MJH-69 Line 16 – MJH 70 Line 3, MJH-80 Line 18 -MJH-84 Line 7, and	Page 3 Line 47 Pages 107-110

	Exhibit A-24 Schedule N7 Page 3.	
MIMO Web Self-Service	MJH-27 Lines 15 - MJH-29 Line 2	Page 4 Lines 53-54 Pages 121-124
Payment Web Self-Service	MJH-36 Line 20 - MJH-38 Line 24	Page 4 Lines 55-56 Pages 125-129

Attachment: None.

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.114b
Respondent: M. Hatsios
Page: 1 of 3

Question: 114. Refer to Exhibit A-12, Schedule B5.7.3 on Customer Service IT projects. For each project of $3.0 million or greater in 2024 and 2025, please:

b. Provide the project phases of development with related timeline and the identify the current phase of development (i.e., needs identification, initial concept development/scoping, system requirements, implementation, completed) and the target in-service date.

Answer: The Customer Service IT projects of $3.0 million or greater in 2024 and 2025 utilize three different methodologies when managing a project's delivery. These methodologies are Agile, Waterfall, and project-specific delivery phases.

1. The following projects utilize the Agile methodology to manage project delivery lifecycle. Delivery cycle in Agile projects is broken down into short time-boxed periods called sprints. Each sprint cycle includes the following phases: Tech refinement/ Analysis, Design, Development, Testing, Go-live/ Deployment, and Post-production. There are instances where multiple sprints may be completed for each phase. The new features and enhancements are deployed per application release calendar.

2024-2025 Projects ($3 million or greater) that utilize the Agile Methodology	Sprint Completion Timeline
Collection Web Self-Service	Bi-weekly
Error Free Communication - Outage Status	Bi-weekly
MIMO Web Self-Service	Bi-weekly
Payment Web Self-Service	Bi-weekly

2. The Regulatory Compliance project utilizes the Waterfall methodology to complete the project delivery lifecycle. This project funds the Customer Relationship & Billing and reporting system changes necessary to comply with the outcome of any MPSC rate orders, to provide funding for emerging regulatory compliance items, and to fund the implementation of new rates and programs as approved by the MPSC (see Hatsios Direct Testimony Page MJH-93 Lines 20-23). Waterfall projects are broken down into phases with durations that align with the development effort

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.114b
Respondent: M. Hatsios
Page: 2 of 3

required for the system functional change. Each project lifecycle includes the following phases: Analysis/Requirements/Design, Build/Development, Testing, Go-live/ Deployment, and Post-production. Specific dates for each phase depend on the extent of the changes and vary by the specific regulatory requirement. Since these projects follow the Waterfall methodology, the enhancements are deployed to align with DTE's defined monthly release calendar.

3. The following 2024-2025 projects utilize project-specific delivery phases.

2024 Advance Analytics Use Cases Implementation: Use Case #1 - Contact Center Journey Mapping	**Start Date**	**Finish Date**
Initiation	4/1/2024	4/1/2024
Design	4/1/2024	4/5/2024
Data Integration	4/8/2024	9/6/2024
Analytics and Insights Development	8/9/2024	10/11/2024
Phase 1 and Phase 2 Testing and Deployment	10/11/2024	12/13/2024
In-Service / Go-Live	12/13/2024	12/13/2024
Warranty	12/13/2024	12/31/2024

2024 Advance Analytics Use Cases Implementation: Use Case #2 - Energy Assistance and EWR	**Start Date**	**Finish Date**
Initiation	2/26/2024	2/26/2024
Requirements / Design	2/26/2024	5/20/2024
Develop deployment pipeline for machine learning model	5/20/2024	6/14/2024
Production deployment and validation of Machine Learning pipeline	6/17/2024	7/15/2024
SAP integration / Agent Assist Development and Testing	5/28/2024	8/9/2024
Go-Live for SAP Changes and Agent Assist	7/26/2024	8/9/2024
Machine Learning pipeline, SAP, Agent Assist-integrated Post-production Testing	8/9/2024	9/16/2024
Warranty	9/17/2024	10/14/2024

2025 Advance Analytics Use Cases Implementation: Use Case #1 - Reducing MPSC Complaints	**Start Date**	**Finish Date**
Initiation	3/11/2025	3/11/2025
Requirements / Design	3/11/2025	5/30/2025

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.114b
Respondent: M. Hatsios
Page: 3 of 3

Develop deployment pipeline for machine learning model	6/2/2025	10/24/2025
Production testing and deployment of Machine Learning pipeline	7/14/2025	12/12/2025
In-Service / Go-Live	12/12/2025	12/12/2025
Warranty	12/15/2025	12/31/2025

2025 Advance Analytics Use Cases Implementation: Use Case #2 - Automating CR Notes	**Start Date**	**Finish Date**
Initiation	2/17/2025	2/17/2025
Requirements / Design	2/17/2025	5/16/2025
Develop deployment pipeline for machine learning model	5/19/2025	6/20/2025
Production deployment and testing of Machine Learning pipeline	6/23/2025	7/11/2025
SAP integration	5/19/2025	8/22/2025
Go-Live for SAP Changes	8/22/2025	8/22/2025
Post-production Testing	8/25/2025	9/26/2025
Warranty	9/29/2025	10/26/2025

	MIGP Customer - Requested Renewable Energy Projects		**Rider 17 – MIGreenPower, Residential and Small Commercial & Industrial (2024)**		**Rider 17 – MIGreenPower, Residential and Small Commercial & Industrial (2025)**	
	Start Date	**End Date**	**Start Date**	**End Date**	**Start Date**	**End Date**
Project Kick-off	8/1/2024	8/31/2024	2/1/2024	3/30/2024	1/2/2025	2/28/2025
Design	9/1/2024	12/31/2024	4/1/2024	7/31/2024	4/1/2025	4/30/2025
Development	1/2/2025	6/30/2025	4/1/2024	9/30/2024	4/1/2025	9/30/2025
Testing	7/1/2025	10/30/2025	7/31/2024	10/30/2024	7/1/2025	10/30/2025
Go-Live	11/30/2025	11/30/2025	11/30/2024	11/30/2024	11/30/2025	11/30/2025
Warranty	12/1/2025	12/31/2025	12/1/2024	12/31/2024	12/1/2025	12/31/2025

Not listed in the table above is the MIGP Scope 3 Billing and Enrollment project as it now has a project delivery year of 2026. While there has been delay in the MIGP Scope 3 Billing and Enrollment project due to the unavailability of generation capacity, the Company fully intends and has plans to complete the MIGP project(s) identified in the rate case.

Attachment: None.

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.114c
Respondent: M. Hatsios
Page: 1 of 2

Question: 114. Refer to Exhibit A-12, Schedule B5.7.3 on Customer Service IT projects. For each project of $3.0 million or greater in 2024 and 2025, please:

c. Provide the project cost by year from inception to completion.

Answer: The project costs by year can be found in the table below.

2024-2025 Projects ($3 million or greater)	Investment Category	Exhibit A-12 B5.7.3 Line No(s).
MIGP Customer - Requested Renewable Energy Projects	Regulatory/Compliance	4
MIGP Scope 3 Billing and Enrollment	Regulatory/Compliance	11
Regulatory Compliance	Regulatory/Compliance	14
Rider 17 – MIGreenPower, Residential and Small Commercial & Industrial	Regulatory/Compliance	15
Advanced Analytics AA Use Cases Implementation	IT Enhancement	18
Collection Web Self-Service[3,4]	Strategic	21 (2022)[1], 29, 31 (2022), 39 (2022)[2], 48 (2022)
Error Free Communication - Outage Status	Strategic	35
MIMO Web Self-Service[3,4]	Strategic	21 (2022)[1], 38 (2022), 39 (2022)[2], 41
Payment Web Self-Service[4]	Strategic	42

[1] 2022 amount of the CR&B Enhancement project allocated to Collection digital self-service is $100K and $200K for MIMO digital self-service. See Hatsios Direct Testimony for the projects that fund Collection digital self-service on Page MJH-21 (Table 3) and MIMO digital self-service on Page MJH-25 (Table 5).

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.114c
Respondent: M. Hatsios
Page: 2 of 2

[2] 2022 amount of the Journey Work Product Transformation Teams project allocated to Collection digital self-service is $2,300K and $3,000K for MIMO digital self-service. See Hatsios Direct Testimony for the projects that fund Collection digital self-service on Page MJH-21 (Table 3) and MIMO digital self-service on Page MJH-25 (Table 5).

[3] The Collection and MIMO Web Self-Service projects are a part of the digital self-service projects that include additional projects whose cost supported the development of the Collection and MIMO digital self-service transactions. These costs are referenced in the table for the year in which it is applicable. The 2022 amounts are shown in the footnotes above.

[4] 2021 IT digital self-service projects outside of the period included in U-21534 supported the development of the Collection, MIMO, and Payment digital self-service transactions. These projects include: IVR Virtual Assistants in the amount of ~$1,100K in 2021 for Collection, Digital Experience Group in the amount of $1,579K in 2021 for MIMO, Digital Transactional Experience in the amount of ~$500K in 2021 for MIMO and in the amount of ~$500K in 2021 for Collection, and Kiosk Experience in the amount of $1,522K in 2021 for Payment. Also, there were 2020 IT capital costs in the amount of $5,183K from the Digital Experience Group that supported MIMO and Outage digital self-service; however, we are unable to break-out the MIMO portion.

Attachment: None.

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.114d
Respondent: M. Hatsios
Page: 1 of 1

Question: 114. Refer to Exhibit A-12, Schedule B5.7.3 on Customer Service IT projects. For each project of $3.0 million or greater in 2024 and 2025, please:

d. Provide a copy of the cost/benefit analysis showing the project was economically justified.

Answer: As outlined in witness Sharma Direct Testimony (see Page PS-7 Line 17 – PS-8 Line 20), DTE IT assigns and utilizes a project prioritization score (PPS) in place of traditional cost benefit analysis for prioritizing all IT investments. The PPS score, business benefit and outcomes supporting each project are provided in the executive summaries, Exhibit A-24, Schedule N1.1.

2024-2025 Projects ($3 million or greater)	Investment Category	Exhibit A-24 N1.1 Reference
MIGP Customer - Requested Renewable Energy Projects	Regulatory/Compliance	Pages 17-19
MIGP Scope 3 Billing and Enrollment	Regulatory/Compliance	Pages 33-34
Regulatory Compliance	Regulatory/Compliance	Pages 43-44
Rider 17 – MIGreenPower, Residential and Small Commercial & Industrial	Regulatory/Compliance	Pages 47-50
Advanced Analytics AA Use Cases Implementation	IT Enhancement	Pages 57-60
Collection Web Self-Service	Strategic	Pages 86-89
Error Free Communication - Outage Status	Strategic	Pages 107-110
MIMO Web Self-Service	Strategic	Pages 121-124
Payment Web Self-Service	Strategic	Pages 125-129

Additionally, for projects that support call volume reduction, these projects are supported by the NPV model, see Exhibit A-24, Schedule N6, Page 3. Of the above 2024-2025 projects, these projects would include a portion of the 2024 Advanced Analytics Use Cases Implementation, and Collection Web Self-Service, MIMO Web Self-Service, and Payment Web Self-Service.

Attachment: None.

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.123a
Respondent: P. Sharma
Page: 1 of 1

Question: 123. Refer to Exhibit A-12, Schedule B5.7.1 on Customer Service IT projects. For each project of $3.0 million or greater in 2024 and 2025, please:

a. Describe the project, what is being done, and why it is necessary to undertake each project.

Answer: The requested information for Customer Service IT projects of $3.0 million or greater in 2024 and 2025 can be found using the references listed below:

Projects $3 million or greater	Witness Sharma's Direct Testimony Page Reference	Exhibit A-24 N1 Reference
Customer Digital Channels and Self-Service Program	PS-41 and PS-42	Pages 95 through 102
Customer Relationship and Billing Program	PS-44 and PS-45	Page 116 through 119
MIGreenPower Program Stabilization	PS-46 and PS-47	Pages 128 and 129
Powerley Customer Platform Application Health	PS-47 and PS-48	Pages 132 and 133
Digital Channels Transformation Program	PS-54 and PS-56	Pages 155 through 158

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.123b
Respondent: P. Sharma
Page: 1 of 1

Question: 123. Refer to Exhibit A-12, Schedule B5.7.1 on Customer Service IT projects. For each project of $3.0 million or greater in 2024 and 2025, please:

b. Provide the project phases of development with related timeline and the identify the current phase of development (i.e., needs identification, initial concept, system requirements, implementation, completed) and the target in-service date.

Answer: The Customer Service IT projects of $3.0 million or greater in 2024 and 2025 utilize Agile methodology to manage project delivery lifecycle. Delivery cycles in Agile projects are broken down into short timeboxed periods called sprints. Each sprint cycle includes the following phases: Tech refinement / Analysis, Design, Development, Testing, Go-live / Deployment, and Post-production.

Since these projects follow the Agile methodology, the new features and enhancements are deployed monthly or bi-weekly per application release calendar. The Delivery timeline for Customer Service IT projects $3.0 million or greater in 2024 and 2025 is shown below:

2024-2025 Projects ($3 million or greater)	Delivery Timeline
Customer Digital Channels and Self-Service Program	Monthly
Customer Relationship and Billing Program	Bi-weekly
MIGreenPower Program Stabilization	Monthly
Powerley Customer Platform Application Health	Monthly
Digital Channels Transformation Program	Bi-weekly

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.123c
Respondent: P. Sharma
Page: 1 of 2

Question: 123. Refer to Exhibit A-12, Schedule B5.7.1 on Customer Service IT projects. For each project of $3.0 million or greater in 2024 and 2025, please:
c. Provide the project cost by year from inception to completion.

Answer: The Customer Service IT projects $3.0 million or greater in 2024 and 2025 are non-discretionary capital investments in the Sustainment and Return-to-Health investment category.
As described in the DTE Five-Year IT Plan 2021-2025 filed in Docket No. U-20642, section 3.B. "Sustainment" investments cover on-going required activities for applying patches, data adjustments, performance tuning, administrative activities (data archiving, certificate expiration) etc.
As described in the DTE Five-Year IT Plan 2021-2025 filed in Docket No. U-20642, section 3.C "Return-to-Health" investment category represents non-discretionary spend, to update systems which are in critical health or end-of-life. These projects require recurring annual investments to continue to sustain or address critical health, or end-of-life.

2024-2025 Projects ($3 million or greater)	Investment Category	Witness Sharma's Direct Testimony Reference	Cost by year from inception to completion
Customer Digital Channels and Self-Service Program	Sustainment	PS-41 and PS-42	Annual
Customer Relationship and Billing Program	Sustainment	PS-44 and PS-45	Annual
MIGreenPower Program Stabilization	Sustainment	PS-46 and PS-47	Annual
Powerley Customer Platform Application Health	Sustainment	PS-47 and PS-48	Annual
Digital Channels Transformation Program	Return to Health	PS-54 and PS-56	Annual

MPSC Case No: U-21534

Requester: AG

Question No.: AGDE-3.123c

Respondent: P. Sharma

Page: 2 of 2

Additional information on Sustainment and Return to Health categories can be found in the Witness Sharma direct testimony PS-13 and PS-14 and DTE Five-Year IT Plan 2021-2025 filed in Docket No. U-20642 (pg. 11,12 Section 3.B,3.C).

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.123d
Respondent: P. Sharma
Page: 1 of 1

Question: 123. Refer to Exhibit A-12, Schedule B5.7.1 on Customer Service IT projects. For each project of $3.0 million or greater in 2024 and 2025, please:

d. Provide a copy of the cost/benefit analysis showing each project was economically justified.

Answer: The Customer Service IT projects $3.0 million or greater in 2024 and 2025 are non-discretionary capital investments in the Sustainment and Return to Health investment category.

As outlined in witness Sharma direct testimony Q14(PS-7 through PS-9), non-discretionary Regulatory/Compliance, Sustainment, and Return-to-Health projects are considered "must do" and, therefore, do not require a cost benefit analysis.

2024-2025 Projects ($3 million or greater)	Investment Category	Witness Sharma's Direct Testimony Page Reference
Customer Digital Channels and Self-Service Program	Sustainment	PS-41 and PS-42
Customer Relationship and Billing Program	Sustainment	PS-44 and PS-45
MIGreenPower Program Stabilization	Sustainment	PS-46 and PS-47
Powerley Customer Platform Application Health	Sustainment	PS-47 and PS-48
Digital Channels Transformation Program	Return to Health	PS-54 and PS-56

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.122
Respondent: P. Sharma
Page: 1 of 1

Question: 122. Refer to Exhibit A-12, Schedule B5.7, pages 1, 2 and 3, on IT projects. Please expand these schedules to include the same actual information for each year 2018 to 2023 and provide it in Excel.

Answer: Please see attached excel 'U-21534 AGDE-3.122 A-12 B5.7 2018-2023 actuals.xlsx'

Attachment: U-21534 AGDE-3.122 A-12 B5.7 2018-2023 actuals.xlsx

Line No.	Description	2018 Actuals ($000)	2019 Actuals ($000)	2020 Actuals ($000)	2021 Actuals ($000)	2022 Actuals ($000)	2023 Actuals ($000)
1	**Shared Asset Expenditures**						
2	Corporate Applications	4,549	3,637	6,240	16,880	17,087	10,728
3	Plant & Field	1,457	4,430	4,590	9,260	7,237	9,475
4	Information Technology for IT	2,777	5,417	2,736	16,673	5,153	3,205
5	Information Protection Security	480	1,321	1,975	1,870	6,063	3,924
6	Infrastructure Operations	7,403	10,101	20,983	21,919	36,190	49,018
7	Enterprise Data Analytics	-	468	6,616	4,771	5,521	4,570
8	Innovations	331	7	3,684	2,227	2,789	3,043
9	Subtotal Corporate Support IT	16,997	25,381	46,824	73,600	80,039	83,964
10	Customer Service - (Sustainment and Return to Health)	18,683	18,508	23,738	20,545	15,252	22,017
11	Customer Service - (Strategic, Enhancements & Compliance)	4,890	3,005	6,108	10,396	28,398	21,476
12	Subtotal Customer Service IT	23,573	21,513	29,846	30,941	43,650	43,493
13	**Grand Totals**	**40,571**	**46,894**	**76,671**	**104,541**	**123,689**	**127,456**

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.127a
Respondent: N. Foley
Page: 1 of 1

Question: 127. Refer to lines 21-25 on page 61 and lines 1-8 on page 62 of Ms. Uzenski's direct testimony on the downtown campus facilities renovation. Please:

a. Explain why employees are required to return to their office only for three days instead of full time. What work efficiencies are gained by having employees at their office location only three days instead of 5-days a week?

Answer: The Company objects for the reason that the request is unclear, vague and incapable of answer in its present form since the Company is unclear regarding the meaning of "work efficiencies."

Subject to this objection, and without waiving this objection, the Company responds as follows:

The decision to require employees to return to their office for three days per week was a corporate policy decision. The Company has not attempted to forecast and/or quantify the efficiency of its workforce under a 3-day vs. 5-day in-office policy.

Attachment: *None*

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.127b
Respondent: T. Uzenski
Page: 1 of 1

Question: 127. Refer to lines 21-25 on page 61 and lines 1-8 on page 62 of Ms. Uzenski's direct testimony on the downtown campus facilities renovation. Please:

b. Why are space updates needed to accommodate only a 3-day work week when pre-Covid the space was sufficient for a 5-day work week?

Answer: Much of the space had been reconfigured to support agile work (unassigned seating where you reserve a workstation when you come in). This allowed us to sell two buildings and eliminate the lease of two buildings. (Ashley Mews, Navitas Building, Northwest Planning, and Farmington TSSC). In order to accommodate everyone being on site at the same time we are moving back to assigned seating but accommodating a larger population as we have overall reduced square footage. Reconfiguration of furniture was required, and workstations were added in collaborative areas to maximize space.

Attachment: *none*

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.127c
Respondent: T. Uzenski
Page: 1 of 1

Question: 127. Refer to lines 21-25 on page 61 and lines 1-8 on page 62 of Ms. Uzenski's direct testimony on the downtown campus facilities renovation. Please:

c. What happened to the furniture, monitors, docking stations, work stations and other equipment that was previously at the office? Why can't employees use or return the equipment that was previously at their office location pre-Covid?

Answer: Furniture that came out of the headquarters (HQ) was reused on projects in service centers and plants and the much older furniture in those areas was salvaged. Also, as employees are working from home two days a week a home office setup is still required. Thus, the monitors, keyboards, mice, and desk chairs that went to employees' homes are still needed in their home office. Therefore, it was required that this equipment be purchased to fully outfit the offices in the HQ. We moved from 2,000 reservable workstations to 4,100 workstations that are assigned to each employee.

Attachment: *none*

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.127d
Respondent: T. Uzenski
Page: 1 of 1

Question: 127. Refer to lines 21-25 on page 61 and lines 1-8 on page 62 of Ms. Uzenski's direct testimony on the downtown campus facilities renovation. Please:

d. Why do all huddle and conference rooms in the GO and SB buildings require audio-visual equipment to be Microsoft Teams enabled now? How has the company managed so far in the past 3 years post Covid-19 without this equipment?

Answer: Not all huddle rooms were Teams enabled. All conference rooms are now Teams enabled to accommodate the return to office and to have the ability to conduct hybrid meetings in any of these rooms. This project added Teams enabled equipment to 88 conference rooms.

Attachment: *none*

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.127e
Respondent: T. Uzenski
Page: 1 of 1

Question: 127. Refer to lines 21-25 on page 61 and lines 1-8 on page 62 of Ms. Uzenski's direct testimony on the downtown campus facilities renovation. Please:

e. Why are conference and huddle rooms needed on the first floor of the Cisler Building lobby at a cost of $4.8 million given that they have managed without those rooms before?

Answer: The space renovated on the 1st floor WCB was unused, nonfunctional space. It was space that was once leased by Lake Trust Credit Union, but they moved to another smaller suite on the 2nd floor; and space that was back office/support space as well as our old energy house demonstration space. These areas were repurposed and made functional through this renovation. The complex lacked larger meeting spaces that could accommodate groups in the 40 – 50 range, and there were times that groups were seeking off-site space that was rented or using the GO Auditorium which then caused larger groups to move off site. This renovation made un-used space useful and filled a need the complex had, and ultimately reduced the use of off-site meeting space.

Attachment: *none*

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.131a
Respondent: T. Uzenski
Page: 1 of 1

Question: 131. Refer to Exhibit A-12, Schedule B5.8, pages 2 and 3. For each project of $2 million or greater in 2023, 2024, and/or 2025, please:

a. Describe the project, what is being done, and why it is necessary to undertake this project.

Answer: See file attached.

Attachment: *U-21534 AGDE-3.131a Facilities and Service Center Projects.pdf*

AGDE – 3.131a

Exhibit A-12, Schedule B5.8

Page 2 - Facilities

Line 7 WSC Building G Roof Replacement:

What: Facilities (asset preservation) has determined that the roof (approximately 335,000 Sqf.) on the Warren Service Center Building G is at the end of its useful life and requires replacement. NTH Consultants, Ltd. (NTH) will develop a technical roofing survey and design, assist with competitive construction bidding, and provide construction services that will provide a long-term solution to current roofing problems.

Why: Degraded, unreliable, roof. Condition is such that the capability for water infiltration and active leaks exists. This would lead to wet insulation and the potential for corrosions and structural degradation of the roof deck, as well as the potential for water entering the building.

Line 8 WSC Primary Roof Replacement:

What: The roof at the Walker Cisler Building is at the end of its useful life and requires replacement. NTH Consultants, Ltd. (NTH) will develop a technical roofing survey and design, assist with competitive construction bidding, and provide construction services that will provide a long-term solution to current roofing problems.

Why: Degraded and unreliable roof. Condition is such that the capability for water infiltration and active leaks exists. This would lead to wet insulation and the potential for corrosions and structural degradation of the roof deck, as well as the potential for water entering the building.

Line 12 Greenwood Energy Center Roof:

What: The roofs at the Greenwood Energy Center are at the end of its useful life and requires replacement. NTH Consultants, Ltd. (NTH) will develop a technical roofing survey and design, assist with competitive construction bidding, and provide construction services that will provide a long long-term solution to current roofing. problems.

Why: Degraded, unreliable, roof. Condition is such that the capability for water infiltration and active leaks exists. This would lead to wet insulation and the potential for corrosions and structural degradation of the roof deck, as well as the potential for water entering the building.

Line 13 Walker Cisler Building Substation and Distribution Replacement: Previously approved in Case No. U-21297.

What: According to the VFA (facilities capital planning tool) data, some of the equipment in the WCB substation and electrical distribution system has reached its end of life and needs to be replaced.

Why: The WCB substation and electrical distribution is being utilized to power the WCB building. The equipment that has reached its end of life needs to be removed and replaced.

Line 14 Plaza Center Distribution Panelboard Replacement:

What: According to the VFA data, some of panelboards in the Plaza Building has reached its end of life and needs to be replaced. In order to identify which ones, need to be replaced, an investigation of the equipment. needs to occur.

Why: The panelboards are currently being utilized in the Plaza building. The equipment that has reached its end of life is unknown.

Line 17 ESOC Chiller Replacement:

What: On February 3, 2022, ESOC chiller #2 and #3 were found to be inoperable. The initial analysis has determined the chillers internal piping and drum had frozen and longer usable and repair will exceed the replacement costs. Provide new design to replace the two chillers to handle the ESOC building load and operate within the design specification, weather conditions and operational requirements.

Why: Facilities management decision to replace the chillers since the ESOC building is considered as a critical DTE operational asset. Cooling is necessary for existing equipment, temporary chillers required to maintain critical controls equipment for extended duration due to long lead procurement duration ($1.5M - 42 mos x $35k). New design for new chillers required to mitigate the risk of future freeze. Additional upgrades might be needed for chiller #1 and chilled water system.

Line 19 WSC Fire Suppression:

What: Provide a new Fire Suppression Pump House System that will provide the proper pressurized main line (and sub mains), for site buildings F,G,L,W and DLAB. The new system will comply with NFPA 24 and all applicable Building and Fire Codes. Due to availability of funding and probable length of project timeline, this project will be a 2 phased project(TBD).

Why: The WSC has an existing Fire Pump System "supply house" and "water reservoir" that has aged well beyond its useful life. Buildings, F, G, L, W and DLAB, are currently being fed by this existing system and as such do not have the proper capacity/flow to provide adequate coverage for these buildings, posing a high insurance risk.

Line 20 WSC Transformer Yard Reorganization: Previously approved in Case No. U-21297.

What: Warren Service Center (WSC) Transformer Yard presents challenges for inventory management, emergency access, and equipment warranty requirements. When a transformer is needed it is difficult to locate and retrieve the appropriate transformer in a timely manner. A reorganization of
the transformer yard is needed to improve equipment access, support inventory management, and address and maintain storage warranty.

Why: The WSC Transformer Yard is not organized such that all equipment is accessible and inventory data is not accurate nor easily maintained. In addition, access to electricity is needed to meet some unit's warranties.

Line 22 WCB Façade Restoration:

What: Repair of any façade deficiencies found during assessment.

Why: City of Detroit requires by code to do an assessment of the facade every 5 years, any repairs needed will result in a capital improvement to the building.

Line 24 Ann Arbor Service Center electric system replacement:

What: According to the VFA data, some of the equipment in the Ann Arbor substation and electrical distribution system has reached its end of life and needs to be replaced.

Why: The Ann Arbor substation and electrical distribution is being utilized to power the Ann Arbor building. The equipment that has reached its end of life needs to be removed and replaced.

Line 25 Redford electric system replacement:

What: According to the VFA data, some of the equipment in the Redford substation and electrical distribution system has reached its end of life and needs to be replaced.

Why: The Redford substation and electrical distribution is being utilized to power the Redford building. The equipment that has reached its end of life needs to be removed and replaced.

Line 26 Shelby Service Center Renovation:

What: Includes asset preservation and infrastructure upgrades including a new roof, removal of a septic tank and connection to the city sewer system, mechanical equipment, bathroom/locker room replacement and interior renovation.

Why: In order to accommodate everyone being on site at the same time we are moving back to assigned seating but accommodating a larger population as we have overall reduced square footage. Reconfiguration of furniture was required and workstations were added in collaborative areas to maximize space.

Line 27 WCB First Floor Conference Rooms: See response to AGDE 3.127e.

Line 28 Office Space Audio/Video: See response to AGDE-3.127d.

Line 29 WCB Office Space Updates: See response to AGDE 3.127b and AGDE-3.127c.

Lines 46, 48, 56 End of Life Replacements: (Construction, Door, Replacement):

What: Routine replacement of assets that reach end of life and disrepair.

Why: According to VFA data building assets are at end of life and need replacement.

Page 3 – Service Center Optimization

Lines 2 and 3 - WSC Site Improvements and Building L Renovation: See Uzenski testimony starting at line 20 on page TMU-63.

Line 7 Western Wayne Renovation: Previously approved in Case No. U-21297.

What: The building was constructed in 1978 and many building systems such as lighting, plumbing, electrical, flooring, and ceilings.

Why: The lighting, plumbing, electrical, flooring, and ceilings are beyond their useful life and need replacing.

Line 8 Western Wayne Garage & Warehouse:

What: The Western Wayne Service Center garage is too small compared to the number of vehicles that are sent to the garage for service. The garage is overused. The garage gets congested and it is difficult to move vehicles in and out of the garage.

Why: Re-design and modify the Western Wayne Service Garage to service more vehicles. Use unused space in the building to give the fleet mechanics more room to work. Re-arrange the garage to improve the use of space.

Line 9 Western Wayne Site Improvements:

What: Includes a parking lot expansion, stormwater management, site lighting, and a perimeter security fence.

Why: Parking lot is in disrepair and current storm water detention ponds are at end of life and need to be upgraded.

Line 11 Waterford Service Center (EXCLUDING ASOC): See Uzenski testimony starting at line 7 on page TMU-65.

Line 12 Ann Arbor Storm Water Improvements: See Uzenski testimony starting at line 3 on page TMU-65.

Line 23 Training Center Renovation (aka Service Center Automated Building Control Systems): See Uzenski testimony starting at line 9 on page TMU-66.

Line 27 Headquarters HVAC/BMS System:

What: Building has an HVAC control system. This project will survey and document the existing system conditions and will follow with a design/specs for a properly designed system and eventually purchase, install a new building HVAC Control System.

Why: The older HVAC system was rendered end of useful life due to the inability to maintain temperature control and energy efficiency throughout the headquarters.

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.131b
Respondent: T. Uzenski
Page: 1 of 1

Question: 131. Refer to Exhibit A-12, Schedule B5.8, pages 2 and 3. For each project of $2 million or greater in 2023, 2024, and/or 2025, please:

b. Provide the project phases of development with related timeline and the identify the current phase of development (i.e., needs identification, initial concept scoping, engineering design, out for bids, construction, completed) and the target in-service date.

Answer: See file attached.

Attachment: *U-21534 AGDE-3.131b&c Cost by Year.xls*

Case No.: U-21534
AGDE-3.131b&c
($000)

From Exhibit: A-12
Schedule: B5.8
Page: 2 of 5

Corporate Staff - Facilities Construction and Upgrades

Exhibit Line No.	Description		12 mos. ending 12/31/2021	Historical 12 mos. ending 12/31/2022	Projected 12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025		Total Cost		In Service Year	Timeline / Phase
7	WSC Bldg G Roof replacement		270	2,228	3,962	5,000	-		11,460		Annual	Construction
8	WSC Primary Roof Replacement (Inc. Demo of Cooling Towers)			9	2,913	-	-		2,922		Annual	Completed
12	Greenwood Energy Center Roofs			-	82	-	2,000		2,082		Annual	Engineering
13	WCB Substation & Distribution Replacement		624	485	4,411	5,100	-		10,620		Annual	Construction
14	Plaza Distribution Panelboard Replacement		364	297	1,868	2,219	5,000		9,749		Annual	Engineering
17	ESOC Chiller Replacement		0	866	1,821	5,000	-		7,687		Annual	Construction
19	WSC Site Fire Suppression / Eliminate Fire Reservoir		0	818	3,162	1,300	-		5,280		Annual	Construction
20	WSC Transfomer Yard Reorganization		0	675	2,170	2,913	-		5,759		Annual	Construction
22	WCB Facade restoration			-	-	-	3,000		3,000		Annual	Initial Concept
24	Ann Arbor SC - Main building electrical system lifecycle replace			-	9	-	2,000		2,009		Annual	Initial Concept
25	Redford - Main building electrical system lifecycle replacement			-	-	-	2,000		2,000		Annual	Initial Concept
26	Renovation - Shelby SC		0	2,407	5,973	1,000	-		9,380		Annual	Construction
27	Renovation - WCB 1 Conference Rooms			-	4,810	-	-		4,810		Annual	Completed
28	Office space updates - Audio/Video			-	-	4,000	-		4,000		Annual	Construction
29	Office space updates - WCB			-	1,455	1,000	-		2,455		Annual	Construction
	End of Life Repairs and Replacements											
46	Construction			4,997	4,429	4,403	4,233		n/a		Annual	Construction
48	Door			905	1,370	1,362	2,054		n/a		Annual	Construction
56	HVAC			6,852	6,621	6,582	9,427		n/a		Annual	Construction

Corporate Staff - Service Center Optimization and Modernization

From Exhibit: A-12
Schedule: B5.8
Page: 3 of 5

Exhibit Line No.	Description		2017-2020	12 mos. ending 12/31/2021	Historical 12 mos. ending 12/31/2022	Projected 12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025		Total Cost		In Service Year	
	Warren Service Center												
2	Warren Service Center Site Improvements			144	1,155	4,086	1,500	-		6,885		2024	Construction
3	Warren Service Center Building L Renovation			112	1,362	1,788	-	4,800		8,062		2025	Construction
										-			
7	Western Wayne Service Center Renovation			1,857	10,080	4,337	-	-		16,274		2025	Completed
8	Western Wayne Garage & Warehouse				-	-	-	4,700		4,700		2025	Initial Concept
9	Western Wayne Site Improvements				-	-	-	2,900		2,900		2025	Initial Concept
										-			
11	Waterford Service Center (excluding ASOC)		3,967	1,993	5,932	25,348	4,293	-		41,534		2024	Construcion
12	Ann Arbor SC Storm Water Improvements				-	-	-	3,000		3,000		2025	Initial Concept
23	Training & Development Center Renovation				2	703	-	7,000		7,705		2026*	Engineering
27	Headquarters HVAC/BMS System				4	2,708				2,712		2024	Construcion

**Note to Training & Development Center Renovation - 2026 is the assumed in service date for the rate case; December 2025 is the updated in-service date*

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.130a
Respondent: T. Uzenski
Page: 1 of 1

Question: 130. Refer to Exhibit A-12. Schedule B5.8, page 1. Please:
a. Expand this schedule to include actual capex for 2018 through 2023 and provide in Excel.

Answer: See file attached.

Attachment: *U-21534 AGDE-3.130a Corporate Staff Capital Expenditures.xls*

U-21534								
AGDE 3.130a								
Capital Expenditures - Corporate Staff								
	Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Projected**	**Projected**
	12 mos. ended	**12 mos. ended**	**12 mos. ended**	**12 mos. ended**	**12 mos. ended**	**12 mos. ended**	**12 mos. ending**	**12 mos. ending**
	12/31/2018	**12/31/2019**	**12/31/2020**	**12/31/2021**	**12/31/2022**	**12/31/2023**	**12/31/2024**	**12/31/2025**
Electric Vehicle Fleet and Maintenance	16,323	30,640	20,698	21,672	43,821	33,155	38,236	42,600
Facilities-Construction & Upgrade	62,126	67,023	47,508	55,128	50,028	62,192	51,952	40,492
Service Center Optimization & Modernization	20,725	20,800	11,694	16,687	30,122	39,877	5,793	28,800
Headquarters Energy Center	1,436	11,260	24,971	-	-			
Security Measures	598	7,552	4,838	4,537	5,812	4,340	838	8,038
NERC-Critical Infrastructure Program	4,203	2,278	1,221	-	-			
Enterprise Automation 1/	6,760	8,307	11,797	-	-			
Other Miscellaneous	1,941	(2,957)	238	(4,091)	(3,185)	(2,087)	150	150
Total Corporate Staff	114,113	144,903	122,965	93,932	126,598	137,477	96,968	120,080
1/ Enterprise Automation is included on Exhibit A-12 B5.7.1 sponsored by Witness Sharma after 2020.								

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-3.130bii
Respondent: T. Uzenski
Page: 1 of 1

Question: 130. Refer to Exhibit A-12. Schedule B5.8, page 1. Please:

b. For the Electric Vehicle Fleet on line1:

ii. Provide the number of vehicles of each type or class purchased each year for 2021 to 2023 and forecasted for 2024 and 2025 with the related dollars.

Answer: See STDE-4.3a through STDE-4.3d.

Attachment: *none*

Adjustments to Capital Expenditures, Rate Base and Depreciation Expense

($000)

Line	Description	Capital Expenditure Reductions [1] 2023 & Prior	2024	2025	Total	Rate Base Reduction	Depreciation Rate [2]	Reduction in Depreciation Expense	Property Tax Millage Rate	Property Tax Adjustment [4]
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Distribution Operations:**									
2	Emergent Replacements		24,526	28,557	53,083	38,805	4.11%	1,595	0.05600	$ 659
3	Customer Connections & Load Growth		14,453	(3,405)	11,048	12,751	4.11%	524	0.05600	$ 388
4	Utility Make Ready Attachments		3,734	10,173	13,907	8,821	4.11%	363	0.05600	$ 100
5	Relocation of I-375 Electrical Facilities		25,000	8,000	33,000	29,000	4.11%	1,192	0.05600	$ 672
6	Electric System Equipment		3,153	3,456	6,609	4,881	4.11%	201	0.05600	$ 85
7	General Plant, Tools, Equipment & Miscellaneous		1,758	1,862	3,620	2,689	4.11%	111	0.05600	$ 47
8	Portable Generators		4,500		4,500	4,500	4.11%	185	0.05600	$ 121
9	Tree Trim Surge Program Savings and Risk Model	6,902	66,900	59,600	133,402	103,602	4.11%	4,258	0.05600	$ 1,984
10	2023 Underspent amount	25,202			25,202	25,202	4.11%	1,036	0.05600	$ 677
11	Strategic Capital Programs - Paul Alvarez: [3]									
12	4.8kV Hardening		73,333	81,800	155,133	114,233	4.11%	4,695	0.05600	$ 1,971
13	Pole and Poletop Maintenance & Modernization			57,550	57,550	28,775	4.11%	1,183	0.05600	$ -
14	Strategic & Service Line OH to UG Pilots		13,744	16,019	29,763	21,754	4.11%	894	0.05600	$ 369
15	Subtransmission Redesign and Rebuild		25,336	2,808	28,144	26,740	4.11%	1,099	0.05600	$ 681
16	Distribution Automation			101,176	101,176	50,588	4.11%	2,079	0.05600	$ -
17	Grid Automation Telecommunications		16,900	15,000	31,900	24,400	4.11%	1,003	0.05600	$ 454
18	**Power Generation:**									
19	Greenwood and Belle River		21,855	8,223	30,078	25,967	3.24%	841	0.05600	$ 587
20	2023 Projects Underspent	3,951			3,951	3,951	3.24%	128	0.05600	$ 106
21	**Nuclear**									
22	Security System Computer	19,033	9,197		28,230	28,230	4.26%	1,203	0.05600	$ 759
23	Plant Radio System	11,332	1,498		12,830	12,830	4.26%	547	0.05600	$ 345
24	Plant Fuel Costs			20,017	20,017	10,009	4.26%	426	0.05600	$ -
25	Other Projects		58,039	56,311	114,350	86,195	4.26%	3,672	0.05600	$ 1,560
26	**Customer Service/IT**									
27	Customer Service projects		5,750	15,393	21,143	13,447	20.00%	2,689		
28	Other IT projects		1,218	2,958	4,176	2,697	20.00%	539		
29	2023 Projects Underspent	34,854			34,854	34,854	20.00%	6,971		
30	**Corporate**									
31	Corporate Office renovations	6,265	8,000		14,265	14,265	7.56%	1,078	0.05600	$ 383
32	Other corporate-wide facilities			24,600	24,600	12,300	7.56%	930	0.05600	$ -
33	Transportation Fleet		4,564	8,187	12,751	8,658	7.56%	655	0.05600	$ 123
34	**EV Programs**		6,979	2,295	9,274	8,127	8.53%	693	0.05600	$ 188
35	**Total**	**$ 107,539**	**$ 390,437**	**$ 520,580**	**$ 1,018,556**	**$ 758,266**		**$ 40,788**		**$ 12,261**
36										
37	Working Capital					25,684				
38										
39	Total Rate Base Deduction					**$ 783,950**				

Source: (1) See AG witness Coppola Direct Testimony.
(2) Depreciation rates from Exhibit A-13, Schedule C6, page 2.
(3) See AG-MNS witness Paul Alvarez Direct Testimony.
(4) Property tax adjustment for 2024 and prior years disallowances x 96% factor x 50% x millage rate. No property taxes on IT software.

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-1.20a
Respondent: T. Uzenski
Page: 1 of 1

Question: 20. Refer to Exhibit A-12, Schedule B4. Please:

a. Explain what is included on line 27, Reg. Asset Ludington, which has a $9.9 million balance in the projected test year.

Answer: The Commission's May 18, 2023 Order in Case No. U-21310 provided for the deferral of costs to restore allegedly defective work performed by Toshiba America Energy Systems Corporation at the Ludington Pumped Storage Plant. The balance reflects capital replacement and repair costs incurred during 2023, offset by anticipated liquidated damages.

Attachment: *none*

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-1.20b
Respondent: M. Guillaumin
Page: 1 of 1

Question: 20. Refer to Exhibit A-12, Schedule B4. Please:

b. Provide a schedule in Excel showing how the cumulative projected costs by major item at January 1 and December 31, 2025 were determined, beginning with the balance in the historical test year.

Answer: The balance in 2025 reflects the same balance as of December 31, 2023. See attached.

Attachment: *U-21534 AGDE-1.20b Ludington Regulatory Asset.xls*

		U-21534	
		AGDE-1.20b	
Ludington Regulatory Asset			
Historical and Projected Balance		$ thousands	
Capital Replacements		13,677	
Accrued unbilled liabilities		803	
O&M Repairs		60	
Liquidated Damages		(4,607)	
Total Regulatory Asset		9,933	

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-21534
Exhibit AG-20
July 26, 2024

Working Capital - Regulatory Asset - Incentive Compensation Balance

Line	Caption or Description	Thousands of Dollars: Projected 2023 Test Requested Amounts*	2023 Actual Performance Results**	2023 Amount Earned	Notes
	(a)	(b)	(c)	(d)	(e)
1	U-20836 Incentive Comp. Requested (Oper Metrics)				
2	AIP	$ 6,029	28.00%	$ 1,688	Col (b) x (c)
3	REP	15,196	28.00%	4,255	Col (b) x (c)
4	Total Requested and Paid by Company	$ 21,225		$ 5,943	L 2 + L 3
5	Amounts Approved for Recovery in Rates (p. 301 of 11/18/2022 Order in U-20836)			$ 12,735	
6	Operational-related Metrics Compensation eared by Company			5,943	L 4 Above
7	Over Recovery By Company & Liability to Customers (Jan 1, 2025)			$ 6,792	L 5 less L 6
8	2025 Negative Amortization Expense (5 Yr. Amortization)			(1,358)	
9	Balance at End of 2025			5,434	L 7 x 80%
10	Average Liability to Customers			$ 6,113	Avg. of L7 & L 8
11	Asset Balance per Company***			3,884	Co. Exh. A-12, Sch B4
12	**Working Capital Reduction**			**$ 9,997**	L 9 Plus L 10

* From page 53 of Witness Cooper's Case U-20836 testimony which was recognized on page 301 of the U-20836 rate order.

** Exhibit AG-21 includes DR AGDE 1.48 with Attachment for the performance percentages achieved.

*** In the deferral account, he Company also included $8.8 million in accrual assuming it would achieve Target Level Performance in 2024. With no actual performance yet achieved such accrual is premature and has been removed from my calculations.

MPSC Case No: U-21534

Requester: AG

Question No.: AGDE-1.48

Respondent: M. Fix

Page: 1 of 1

Question: 48. Refer to Exhibit A-21, Schedules K2, K3, and K4, regarding Incentive Compensation. Please provide a schedule in Excel with each of the 2023 operational metrics and for each of the three groupings (DTE Electric, DTE Nuclear Generation, and DTE LLC) showing the performance results by identifying for each such metric for performance at (a) below Threshold; (b) at or above Threshold, but below Target; (c) at Target; (d) between Target and Maximum; and (e) at the Maximum.

Answer: Please see response to TMS-1.4

Attachment: None

DTE Electric Company
Case No. U-21534
AGDE-1.48
AIP, AIP Executives and REP Operating Measure Results: 2019 - 2023

Line No	Description	AIP 2019	AIP 2020	AIP 2021	AIP 2022	AIP 2023	AIP Average	AIP Executives 2019	AIP Executives 2020	AIP Executives 2021	AIP Executives 2022	AIP Executives 2023	AIP Executives Average	REP 2019	REP 2020	REP 2021	REP 2022	REP 2023	REP Average	Combined Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
1	**DTE Electric**																			
2	Less than Threshold	4	3	4	2	6		4	3	4	2	6		4	3	4	2	6		
3	Between Threshold and Target	3	0	2	2	1		3	0	2	2	1		3	0	2	2	1		
4	Target	0	1	0	1	0		0	1	0	1	0		0	1	0	1	0		
5	Between Target and Maximum	4	6	3	3	1		4	6	3	3	1		2	5	2	2	0		
6	Maximum	2	4	0	1	1		2	4	0	1	1		2	4	0	1	1		
7		13	14	9	9	9		13	14	9	9	9		11	13	8	8	8		
8																				
9	Sum of Performance for all measures	1,124%	1,544%	483%	790%	389%		1,124%	1,544%	483%	847%	425%		774%	1,273%	366%	637%	238%		
10																				
11	Average Performance	86.5%	110.3%	53.6%	87.8%	43.2%	76.3%	86.5%	110.3%	53.6%	94.1%	47.2%	78.3%	70.3%	97.9%	45.7%	79.6%	29.8%	64.7%	
12																				
13	**Nuclear Generation**																			
14	Less than Threshold	3	1	2	4	4		3	1	2	4	4		3	1	2	3	4		
15	Between Threshold and Target	0	1	3	2	0		0	1	3	2	0		0	0	2	1	0		
16	Target	0	1	0	0	0		0	1	0	0	0		0	1	0	0	0		
17	Between Target and Maximum	3	1	1	0	2		3	1	1	0	2		1	1	1	0	1		
18	Maximum	2	3	1	2	2		2	3	1	2	2		2	3	1	3	2		
19		8	7	7	8	8		8	7	7	8	8		6	6	6	7	7		
20																				
21	Sum of Performance for all measures	803%	786%	550%	411%	593%		8.025	7.864	5.499	461%	657%		433%	660%	432%	521%	413%		
22																				
23	Average Performance	100.3%	112.3%	78.6%	51.3%	74.1%	83.3%	100.3%	112.3%	78.6%	57.6%	82.1%	86.2%	72.2%	110.0%	72.0%	74.5%	58.9%	77.5%	
24																				
25	**DTE LLC**																			
26	Less than Threshold	5	5	3	1	6		5	5	3	1	6		5	5	3	1	6		
27	Between Threshold and Target	3	0	1	1	1		3	0	1	1	1		3	0	1	1	1		
28	Target	0	1	0	2	0		0	1	0	2	0		0	1	0	2	0		
29	Between Target and Maximum	4	6	4	3	1		4	6	4	3	1		3	5	3	2	0		
30	Maximum	5	5	0	1	0		5	5	0	1	0		4	5	0	1	0		
31		17	17	8	8	8		17	17	8	8	8		15	16	7	7	7		
32																				
33	Sum of Performance for all measures	1,631%	1,732%	533%	864%	222%		16.313	17.323	5.331	924%	235%		1,207%	1,439%	404%	678%	88%		
34																				
35	Average Performance	96.0%	101.9%	66.6%	107.9%	27.8%	80.0%	96.0%	101.9%	66.6%	115.5%	29.4%	81.9%	80.5%	90.0%	57.7%	96.9%	12.6%	67.5%	
36																				
37	**Total**																			
38	Less than Threshold	12	9	9	7	16		12	9	9	7	16		12	9	9	6	16		
39	Between Threshold and Target	6	1	6	5	2		6	1	6	5	2		6	0	5	4	2		
40	Target	0	3	0	3	0		0	3	0	3	0		0	3	0	3	0		
41	Between Target and Maximum	11	13	8	6	4		11	13	8	6	4		6	11	6	4	1		
42	Maximum	9	12	1	4	3		9	12	1	4	3		8	12	1	5	3		
43		38	38	24	25	25		38	38	24	25	25		32	35	21	22	22		
44																				
45	Sum of Performance for all measures	3,558%	4,063%	1,566%	2,064%	1,204%		3,558%	4,063%	1,566%	2,231%	1,316%		2,414%	3,373%	1,202%	1,837%	739%		
46																				
47	Average Performance	93.6%	106.9%	65.2%	82.6%	48.1%	79.3%	93.6%	106.9%	65.2%	89.3%	52.7%	81.5%	75.4%	96.4%	57.2%	83.5%	33.6%	69.2%	76.7%
48																				
49																				
50	**Total**																			
51	Less than Threshold	12	9	9	7	16		12	9	9	7	16		12	9	9	6	16		
52	Between Threshold and Target	6	1	6	5	2		6	1	6	5	2		6	0	5	4	2		
53	Target	0	3	0	3	0		0	3	0	3	0		0	3	0	3	0		
54	Between Target and Maximum	11	13	8	6	4		11	13	8	6	4		6	11	6	4	1		
55	Maximum	9	12	1	4	3		9	12	1	4	3		8	12	1	5	3		
56	Total Measures	38	38	24	25	25		38	38	24	25	25		32	35	21	22	22		
57																				
58	Total Measures at Target and Above	20	28	9	13	7		20	28	9	13	7		14	26	7	12	4		
59																				
60	Percentage of Measures at Target and Above	52.6%	73.7%	37.5%	52.0%	28.0%	48.8%	52.6%	73.7%	37.5%	52.0%	28.0%	48.8%	43.8%	74.3%	33.3%	54.5%	18.2%	44.8%	47.4%

MPSC Case No: U-21534

Requester: AG

Question No.: AGDE-4.156a.

Respondent: P. Bennett

Page: 1 of 1

Question: 156. Refer to Exhibit A-13, Schedule C5.9.2 on the ACPP and TOD. Please:
a. Provide a list of each amount of $100,000 and greater spent on ACPP and TOD for each year and explain why that expense was necessary and justified. Provide this information in Excel with the remaining total amount for items below $100,000 that totals to the amount spent each year.

Answer: Please refer to the excel file AGDE-4.156a tab for cost explanations.

Attachment: *U-21534 AGDE-4.156a. ACPP and TOD Cost Deferrals*

Michigan Public Service Commission								Case No.:	U-21534	
DTE Electric Company								Exhibit:	A-13	
Advanced Customer Pricing Pilot (ACPP) & Time of Day (TOD)								Schedule:	C5.9.2	
Regulatory Asset Deferral								Witnesses:	M. Hatsios	
($000)									J. Sparks	
									P. Bennett	
								Page:	1 of 1	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	**Description**	**Actual CY 2019**	**Actual CY 2020**	**Actual CY 2021**	**Actual CY 2022**	**Projected CY 2023**	**Projected CY 2024**	**Projected CY 2025**	**Total**	**Sponsoring Witness**
1	**Advanced Customer Pricing Pilot Deferral (Note 1)**									
2	Information Technology	58	862	1,302	321	-	-	-	2,542	M. Hatsios
3	Customer Outreach	107	1,512	1,347	-	-	-	-	2,966	P. Bennett
4	Customer Service	-	-	-	-	-	-	-	-	M. Hatsios
5	Evaluation, Monitoring, & Verification and Operational Support	-	283	171	172	-	-	-	626	P. Bennett
6	Insight	-	358	100	6	-	-	-	464	M. Hatsios
7	Total ACPP Deferral	165	3,015	2,920	499	-	-	-	6,599	
	1/ Authorization to defer ACPP project costs to regulatory asset per order in Case No. U-20602									
		Actual CY 2019	**Actual CY 2020**	**Actual CY 2021**	**Actual CY 2022**	**Projected CY 2023**	**Projected CY 2024**	**Projected CY 2025**	**Total**	**Sponsoring Witness**
8	**Time of Day Implementation Project Costs Deferral (Note 2)**									
9	Information Technology	-	-	-	1,601	881	-	-	2,482	M. Hatsios
10	Customer Outreach	-	-	-	2,044	453	-	-	2,497	P. Bennett
11	Customer Service	-	-	-	-	5,152	-	-	5,152	M. Hatsios
12	Subtotal TOD Expense	-	-	-	3,644	6,486	-	-	10,130	
13	Less TOD Expense thru November 18, 2022	-	-	-	(1,665)	-	-	-	(1,665)	
14	Total TOD Deferral	-	-	-	1,979	6,486	-	-	8,465	
	2/ Authorization to defer TOD project costs to regulatory asset per order in Case No. U-20836 (effective November 2022)									

Michigan Public Service Commission									Case No.	U-21534							
DTE Electric Company										AGDE-4.156a.							
Advanced Customer Pricing Pilot (ACPP) & Time of Day (TOD)									Witnesse	M. Hatsios							
Regulatory Asset Deferral										P. Bennett							
($000)																	
									Page:	1 of 1							
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)		(j)						
Line		Actual	Actual	Actual	Actual	Projected	Projected	Projected									
No.	**Description**	**CY 2019**	**CY 2020**	**CY 2021**	**CY 2022**	**CY 2023**	**CY 2024**	**CY 2025**	**Total**		**Sponsoring Witness**	**Description**	**CY 2019**	**CY 2020**	**CY 2021**	**CY 2022**	**CY 2023**
1	Advanced Customer Pricing Pilot Deferral (Note 1)																
2	Information Technology	58	862	1,302	321	-	-	-	2,542		M. Hatsios	**Information Technology**	IT delivery lead and other IT contract resources performed design and development activities for AMI work.	Preparation work for pilot launch end of March/April. Launch post-poned to 2021 due to the COVID pandemic. Continued work on validation of designs and testing.	Completed development and performed testing. Converted pilot customers to the new rate. Remainder of the year IT was in warranty and extended warranty phase. April - May validation of bill accuracy. July - Sept validation of AMI interval calculations are accurate. Oct - Dec extended warranty phase.	Continued post production support and monitoring. Removed programming for self-service rate sign-up for the end of the pilot..	
3	Customer Outreach	107	1,512	1,347	-	-	-	-	2,966		P. Bennett	**Customer Outreach**	Research was conducted with focus groups for messge testing to ensure communications were easy for customers to understand.	Developed 7 mailings and emails including a brochure about upcoming program and potential savings,as well as a welcome kit with an external agency. A tool was implemented to execute the email communications. In addition, two videos were created for the pilot website to introduce the "shift and save program" as well as how to save money on the new rate. A website was stood up for all customer facing information to learn about the program for both opt-in group and seperate for opt-out group for two rates being tested.	Final communicationwas sent to customer indicating pilot was over, and full TOU roll out would happen in future. Customer that participated in the survey were paid their incentive for participation in the survey ($25 per each survey: 3 surveys available to recieve incentive).		
4	Customer Service	-	-	-	-	-	-	-	-		M. Hatsios	**Customer Service**					
5	Evaluation, Monitoring, & Verification and Operatio	-	283	171	172	-	-	-	626		P. Bennett	**Evaluation, Monitoring, & Verification and Operational Support**		EM&V provided analysis of entire 1.9M residential customers currently on D1 to develop representative sample of 200 customers to offer the pilot. Developed how much each customers would save if "shifted their usage" to off-peak times based off historical data to use in communications.	Developed and administered participant surveys, and customer incentives for taking the survey.	Analyzed data regarding how customers changed behavior to shift usage. In addition, determined optimal communications, communication channels and tools for web for the full TOU roll out.	
6	Insight	-	358	100	6	-	-	-	464		M. Hatsios	**Insight**		Developed the TOU rate elements in the Insight App. Development included building hourly data to visualize, budget setting and forecasting, high bill alert metadata, notifications, hourly rate info for budget breakdowns, enhance visualization, and budget calculator integration.	Performed testing and regression testing.	Wrap up costs.	
7	Total ACPP Deferral	165	3,015	2,920	499	-	-	-	6,599								
	1/ Authorization to defer ACPP project costs to regulatory asset per order in Case No. U-20602																
		Actual	Actual	Actual	Actual	Projected	Projected	Projected					**CY 2019**	**CY 2020**	**CY 2021**	**CY 2022**	**CY 2023**
8	Time of Day Implementation Project Costs Deferral (Note 2)	CY 2019	CY 2020	CY 2021	CY 2022	CY 2023	CY 2024	CY 2025	Total		Sponsoring Witness						
9	Information Technology	-	-	-	1,601	881	-	-	2,482		M. Hatsios	**Information Technology**				Program was set up to transition all residential customers to TOD, except for those in TOD-exempt programs. Re-configured the website, the insight app, and updated all remaining AMI meters to be interval based instead of register based to provide for TOD billing.	Peformed testing on changes for accuracy. After customer conversion in the end of March/early April, the project was in hypercare through the end of June to allow the customers time to receive their first bill.
10	Customer Outreach	-	-	-	2,044	453	-	-	2,497		P. Bennett	**Customer Outreach**				Research (focus groups) for messaging since the rate would no longer be opt-out. Pre-paid majority of the cost for two customer communications - direct mail and email.	Remainder of cost of printing and developing welcome kits sent to 2M customers. Welcome kit explained the rate and new tools to ensure customer could understand their usage and new rate.
11	Customer Service	-	-	-	-	5,152	-	-	5,152		M. Hatsios	**Customer Service**					Labor charges and additional training and surge staff for the expected call spike due to new rate implementation.

MPSC Case No: U-21534

Requester: AG

Question No.: AGDE-4.157a.

Respondent: R. Steudle

Page: 1 of 1

Question: 157. Refer to lines 3-10 on page 13 of Ms. Steudle's direct testimony on the tree trimming program. Please provide the following information in Excel: a. The number of customer power outages incurred each year from 2012 to 2023 due to tree or vegetation caused damage or events.

Answer: See attached – this data reflects customer interruptions identified as vegetation related based on the methodology used for the ETTP effectiveness analysis.

Attachment: *U-21534 AGDE-4 157a Customer Interruptions*

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Customers Interrupted	959,883	991,109	1,303,242	870,802	957,896	1,748,339	1,326,949	1,477,637	1,287,891	1,003,029	879,774	1,445,908
U-21534 AGDE-4 157a Customer Interruptions												

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-4.157b.
Respondent: R. Steudle
Page: 1 of 1

Question: 157. Refer to lines 3-10 on page 13 of Ms. Steudle's direct testimony on the tree trimming program. Please provide the following information in Excel: b. Provide the number of catastrophic storms and grey sky days, separately, for each year 2012 to 2023.

Answer: DTE objects for the reason that the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, but subject to it, the Company responds as follows:

The cited testimony discusses changes in the measurement of the tree trim program's effectiveness at the conclusion of the surge. The changes are necessitated by the fact that all circuit miles will have been trimmed to the ETTP, there is no discussion of weather and no mention of the weather - related conditions used in the question.

Attachment: *None*

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-4.159d.
Respondent: R. Steudle
Page: 1 of 1

Question: 159. Refer to lines 10-23 on page 16 of Ms. Steudle's direct testimony on the tree trimming surge program cost escalation. Please: d. Provide the actual cost per mile for distribution surge tree trimming and for on-cycle, separately, for each year 2012 to 2023 and forecasted for 2024 and 2025 in Excel.

Answer: The Company objects for providing figures for years 2012-2018 for the reason that the information requested is not relevant nor is it reasonably calculated to lead to the discovery of admissible evidence. The Surge program started in 2019; therefore, the cost escalation associated with the surge program is relevant from that year forward. Without waiving this objection, the Company responds as follows:

The provided data is also for miles and costs related to O&M and the regulatory asset to align with the funding sources for the Surge program. Assuming surge miles refers to reclaim miles that had not been trimmed to the ETTP specification, see the attached document for the information requested for years 2019-2025.

Attachment: *U-21534 AGDE 4.159c-f -01 Miles and Cost*

U-21534 AGDE 4.159d -01 Miles and Cost

		2019	2020	2021	2022	2023	2024 & 2025
	Distribution Reclaim $/Mile	$ 29,403	$ 29,375	$ 28,507	$ 43,695	$ 35,086	$ 33,832
	Distribution On-Cycle $/Mile			$ 17,319	$ 18,037	$ 25,496	$ 30,031

MPSC Case No: U-21534

Requester: AG

Question No.: AGDE-4.163a.

Respondent: R. Steudle

Page: 1 of 1

Question: 163. Refer to lines 1-2 on page 21 of Ms. Steudle's direct testimony on paying contractors wage premiums to perform tree trimming surge program work. Please provide the following information in Excel: a. The premium cost paid for each year 2018 to 2023 and forecasted for 2024 and 2025.

Answer: See attachment from the response to AGDE-4.160a (tab Outsource Premium).

Attachment: *None.*

	2019-2022 Act	2023-2025 Forecast*	**Total**
U-20162	$38.89	$6.56	**$45.46**
Actuals/Forecast	$64.63	$50.53	**$115.16**
Net Impact			**$69.70**
*2023 forecast based on 8+4 forecast, 2024-2025 based on the estimated workforce needed to complete the Surge			

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-4.163b.
Respondent: R. Steudle
Page: 1 of 1

Question: 163. Refer to lines 1-2 on page 21 of Ms. Steudle's direct testimony on paying contractors wage premiums to perform tree trimming surge program work. Please provide the following information in Excel: b. The number of companies that were paid and will be paid the premium each year 2018-2025, the amount paid to each company, and the number of trimmers within each company.

Answer: The Company objects for the reason that the information requested consists of confidential, proprietary, and/or commercial information, the disclosure of which would cause the Company, its ratepayers, and its customers competitive harm. Without waiving this objection, but subject to it, the Company responds as follows:

See the attached file showing aggregate payments to local and outsourced vendors.

Attachment: *U-21534-AGDE-4.163b - Premium Cost*

DTEE Response to AGDE-4.163b

	2019	2020	2021	2022	2023	2024 & 2025
Number of companies	7	6	7	7	5	4
Total Premiums	$8.4	$12.7	$14.4	$29.2	$16.0	$34.5

	2019	2020	2021	2022	2023	2024 & 2025
Local	894	918	844	989	870	900
Outsource	239	246	412	650	412	500
Total	**1133**	**1164**	**1256**	**1639**	**1282**	**1400**

U-21534 AGDE-4.163b - Premium Cost

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-4.164b.
Respondent: R. Steudle
Page: 1 of 1

Question: 164. Refer to lines 1-14 on page 21 of Ms. Steudle's direct testimony on the incremental cost of programmatic additions. Please: b. Provide the number of students enrolled each year, the number that graduated and became part of the Company's tree trimming program each year, and the number of graduates who are still part of the Company's tree trimming program of the total number who participated in the academy.

Answer:

	2021	2022	2023
Trained	71	96	54
Graduated	58	90	53
Placed	49	55	27

Of the students placed with a tree contractor – 74 are still working as part of the tree trimming program. Over half the graduates from the program are Detroit residents.

Attachment: *None*

Michigan Public Service Commission
DTE Electric Company
Tree Trim Regulatory Asset - Return On
Projected 12 Month Period Ending December 31, 2025, as adjusted by AG
($000)

Exhibit: AG-25
Case No.: U-21534
July 26, 2024
Page: 1 of 1

Line No.	(a) Description	(b) Test Period Amount	(c) Reference
1	**Return on Tree Trim Regulatory Asset**		
2	Average Balance Regulatory Asset	$ 231,950	Line 16
3	Deferred Tax Liability	(60,075)	- Line 2 x 25.9% Composite Tax Rate
4	Average Net Rate Base	171,875	
5	Authorized Rate of Return on Permanent Capital (pretax)	5.76%	Exhibit A-14, Schedule D1
6	Return on Tree Trim	$ 9,900	

		2019-A	2020-A	2021-A	2022-A	2023	2024	2025	
7	**Tree Trim Regulatory Asset**								
8	#REF!	43,300	74,100	70,500	58,200	67,000	52,700	43,700	Exhibit A-13 C5.6.1, Line 2
9	Carrying Charges through April 30, 2020 1/		1,200						
10	Additional Funding Request	-	-	-	-	-	-	-	Exhibit A-13 C5.6.1, Line 3
11	Total Tree Trim Reg Asset Deferral	43,300	75,300	70,500	58,200	67,000	52,700	43,700	
12	Total Tree Trim Reg Asset Cumulative	43,300	118,600	189,100	247,300	157,400	210,100	253,800	Cumulative Line 11
13	Approved for Securitization 2/				(156,900)				Case U-21015
14	Cumulative Balance at December 31				90,400	157,400	210,100	253,800	
15	Cumulative Balance at December 31						210,100	253,800	Assumes 100% of annual spend
16	Average Balance							231,950	

Source: Exhibit A-11, Schedule A1.1.

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-21534**
DTE Electric - Electric Rate Case **Exhibit AG-26**
July 26, 2024
Recommended Capital Structure & Cost Rates for Test **Page 1 of 1**
Year Ending December 31, 2025

(Millions of Dollars)

Line	Description	Capital Structure: Capital Balances*	Capital Structure: % Permanent Capital	Capital Structure: % 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	$ 8,668.8	50.0%	39.21%	4.24%	1.66%	1.0000	1.66%
2	Preferred Stock	-	0.0%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Equity	8,668.7	50.0%	39.21%	9.85%	3.86%	1.3496	5.21%
4	Total Permanent Capital	17,337.5	100.0%	78.42%		5.52%		6.88%
5	Short Term Debt	509.5		2.30%	5.76%	0.13%	1.0000	0.13%
6	Deferred Income Taxes	4,229.6		19.13%	0.00%	0.00%	1.0000	0.00%
7	JDITC							
8	Long Term Debt	15.7		0.07%	4.24%	0.00%	1.0000	0.00%
9	Preferred Stock	-		0.00%	0.00%	0.00%	1.3496	0.00%
10	Common Equity	15.7		0.07%	9.85%	0.01%	1.3496	0.01%
11	Total Capitalization & Cost Rates	$ 22,108.0		100.00%		**5.67%**		**7.02%**

Notes

* All capital balances per Company Exhibit A-14, Schedule D1.

** All cost rates per Company Exhibit A-14, Schedule D1 except for Common Equity which is set forth on Exhibit AG-27

*** Conversion factors per Company Exhibit A-14, Schedule D1.

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21534**
DTE Electric - Electric Rate Case | **Exhibit AG-27**
July 26, 2024
Summary of Cost of Common Equity Capital Analysis | **Page 1 of 1**

Line	Description	Relative Weighting	Peer Group	Note
	(a)	(b)	(c)	(d)
1	Discounted Cash Flow (DCF) Approach	50.00%	9.26%	1
2	Capital Asset Pricing Model (CAPM) Approach	25.00%	10.57%	2
3	Equity Risk Premium Approach	25.00%	10.10%	3
4	**Calculated Cost of Common Equity (Sum of Col. (b) x (c) for each line)**		**9.80%**	
5	**Rounding**		**0.05%**	4
6	**Cost of Common Equity for Rate Case Purposes**		**9.85%**	

Note 1 See Exhibit AG-28
Note 2 See Exhibit AG-29
Note 3 See Exhibit AG-30
Note 4 Reflects the potential effects of increasing interest rates on the DCF Approach and establishing a more gradual approach to adjusting the Company's ROE to the true cost of Common Equity

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21534**
DTE Electric - Electric Rate Case | **Exhibit AG-28**
July 26, 2024
Discounted Cash Flow (DCF) Application |
(See Equation Below)

Line	Company	Ticker	Stock Price*	Projected 2024-25 Avg. Dividend**	Dividend Yield Col. (d)/(c)	EPS Growth Rate*** Value Ln Long Trm Growth	EPS Growth Rate*** Analysts 5 Yr Growth p/Yahoo	EPS Growth Rate*** Average of Col. (f) & (g)	DCF ROE for Proxy Co. Col. (e) + (h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Alliant Energy	LNT	50.91	$ 1.98	3.89%	N/M	N.M	N.M	N/M
2	Ameren	AEE	73.29	2.77	3.78%	6.37%	5.50%	5.94%	9.71%
3	Avista	AVA	37.06	1.96	5.29%	5.30%	6.20%	5.75%	11.04%
4	Black Hills	BKH	55.72	2.65	4.76%	3.97%	0.70%	3.97%	8.73%
5	CMS Energy	CMS	61.91	2.12	3.42%	4.49%	N.M	4.49%	7.92%
6	Consolidated Edison	ED	94.96	3.36	3.54%	5.54%	6.09%	5.82%	9.35%
7	IDACORP	IDA	95.68	3.40	3.55%	5.29%	4.40%	4.84%	8.40%
8	Northwestern	NWE	51.45	2.62	5.09%	5.71%	4.50%	5.10%	10.20%
9	PNM Resources	PBM	37.77	1.61	4.26%	3.81%	4.42%	4.12%	8.38%
10	Public Service Enterprise Group	PEG	73.41	2.47	3.36%	6.98%	5.60%	6.29%	9.65%
13	**Average**				**4.09%**	**5.27%**	**4.68%**	**4.63%**	***9.26%***

Notes
* High-Low Average Prices for the 30 days May 1 to June 12, 2024 per Yahoo
** From the Value Line Investment Survey Publications of April 10, May 10 and June 7, 2024
*** Columns (f) and (g) are from AG workpapers
N/M Low and High Growth Rates eliminated

Equation **R = D/P + g** *Where* **R** = the required return on the equity security; **P** = the current price of the equity security; **D** = the next dividend on the security; **g** = the expected growth rate of earnings

Comparison of DCF Results by Company (AG versus DTEE results)

			DCF Results**			
	AG Peer Company	**Ticker**	**AG Results**	**AG Results Excl ED&PNM**	**DTEE Results**	**Variance Col c - e**
	(a)	(b)	(c)	(d)	(e)	(f)
1	Alliant Energy	LNT	N/M	N/M	10.70%	
2	Ameren	AEE	9.71%	9.71%	9.20%	
3	Avista	AVA	11.04%	11.04%	11.50%	
4	Black Hills	BKH	8.73%	8.73%	9.60%	
5	CMS Energy	CMS	7.92%	7.92%	10.50%	
6	Consolidated Edison*	ED	9.35%			
7	IDACORP	IDA	8.40%	8.40%	7.90%	
8	Northwestern	NWE	10.20%	10.20%	9.50%	
9	PNM Resources*	PBM	8.38%			
10	Public Service Enterprise Group	PEG	9.65%	9.65%	9.40%	
	Average (Excl. PNM Resources & Cosol. Edison)		**9.26%**	**9.38%**	**9.79%**	**0.52%**

Conclusion:	Exclude PNM and Consolidated Edison	0.11%
	Use DTEE DCF rates	0.41%
	Total Variance AG Case vs. Company Case	**0.52%**

* These two companies are not in the DTEE sponsored peer group

** AG results from page 1 of this exhibit
DTEE results from Exhibit A-14, Schedule D5.7, page 1, Panel A, column 3

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21534**
DTE Electric - Electric Rate Case | **Exhibit AG-29**
July 26, 2024
Capital Asset Pricing Model Application |
(See Equation Below)

Line	Company	Ticker	Common Equity to Capital %	Current Beta (*B*)	Risk Premium (R*p*)	Beta x Risk Premium Col. (d) x (e)	Projected 2025 Risk Free Rate (R*f*)	K*e* or 2025 CAPM ROE for Proxy Co. Col. (e) + (f)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Alliant Energy	LNT	42.8%	0.90	7.17%	6.45%	4.05%	10.50%
2	Ameren	AEE	41.7%	0.90	7.17%	6.45%	4.05%	10.50%
3	Avista	AVA	49.2%	0.95	7.17%	6.81%	4.05%	10.86%
4	Black Hills	BKH	41.5%	1.05	7.17%	7.53%	4.05%	11.58%
5	CMS Energy	CMS	31.5%	0.85	7.17%	6.09%	4.05%	10.14%
6	Consolidated Edison	ED	49.3%	0.80	7.17%	5.74%	4.05%	9.79%
7	IDACORP	IDA	51.3%	0.85	7.17%	6.09%	4.05%	10.14%
8	Northwestern	NEW	49.6%	0.95	7.17%	6.81%	4.05%	10.86%
9	PNM Resources	PBM	33.6%	0.90	7.17%	6.45%	4.05%	10.50%
10	Public Service Enterprise Group	PEG	44.0%	0.95	7.17%	6.81%	4.05%	10.86%
13	**Average**		**43.5%**	**0.91**	**7.17%**	**6.52%**	**4.05%**	***10.57%***
14	High							11.58%
15	Low							9.79%

Sources
Column (c) From Data included in SEC filings
Column (d) From the Value Line Investment Survey Publications of April 19, May 10 and June 7, 2024
Column (e) Historic average - 1926 to 2022 Ibbotson returns of Stock Market vs. Yield on Government Bonds
Column (g) Average 2025 30 Year U.S. Treasury Rate

	Blue Chip Economic Indicators		
	Jan. 2024	**May 2024**	**Average**
10 Yr. Treasury Rate	3.70%	4.00%	
July 2024 Spread	0.20%	0.20%	
Est. 30 Yr. Treasury Rate	**3.90%**	**4.20%**	**4.05%**

Equation for CAPM K*e* = R*f* + (*B* x 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 | **Case No. U-21534**
DTE Electric - Electric Rate Case | **Exhibit AG-30**
July 26, 2024
Electric Utility Equity Risk Premium Approach | **Page 1 of 1**

Line	Description	Projected Test Period	Note
	(a)	(c)	(d)
1	**Proxy Group Debt Ratings (S & P)**	**A to BBB**	
2	**Number of Proxy Companies**	**10**	
	Build-up of Common Equity Rate of Return		
3	Long Term US Treasury Rate Projection	4.05%	1
4	Corporate Spread Over Treasury Bond Rate	1.67%	2
5	Sub Total (Line 2 + Line 3)	5.72%	
6	Historical Spread - Utility Common Stocks over Bonds	4.38%	3
7	**Cost of Common Equity (Line 5 + Line 6)**	***10.10%***	

Notes
1 See risk free rate from AG CAPM analysis
2 Reflects the average spread in 2022 of "A" rated issues (155 BP) and "BBB" issues (179 BP) based on analysis of Exhibit A-18, Schedule H
3 Historical average per AG workpapers

ROEs Under 9.9%**

Line	Electric Company	Jurisdiction & Order Date			ROE Awarded in 2022	ROE Awarded in 2023	Parent Company	Pub. Finan'ls Avail.	Long Term Debt Issued Since Date of Rate Order
1	Niagara Mohawk Power	NY	Jan. 20	2022	9.00%		National Grid, PLC	Foreign	
2	Southwestern Public Service	NM	Feb. 16	2022	9.35%		Xcel Energy	Yes	May 3, 2022 $700M, 30 Yr. at 4.6%
3	Indiana Michigan Power	IN	Mar. 2	2022	9.70%		American Electric Power	Yes	Feb 27, 2023 $850M, 10 Yr. at 5.625%
4	Public Service of Colorado	CO	Mar. 16	2022	9.30%		Xcel Energy	Yes	May 3, 2022 $700M, 30 Yr. at 4.6%
5	Orange & Rockland Utilities	NY	Apr. 14	2022	9.20%		Consolidated Edison	Yes	Nov. 9, 2022 $700M, 30 Yr. at 6.15%
6	Portland General Electric	OR	Apr. 25	2022	9.50%		Portland General Electric	Yes	Jan 3, 2023 $200M, 7 Yr. and 10 Yr at 5.47% & 5.56%
7	Unitil Energy Systems	NH	May 12	2022	9.20%		Unitil	Yes	
8	Southwestern Electric Power	AR	May 23	2022	9.50%		American Electric Power	Yes	Feb 27, 2023 $850M, 10 Yr. at 5.625%
9	Green Mountain Power	VT	Aug. 31	2022	8.57%		Enegir	Private	
10	Oklahoma Gas & Electric	OK	Sep. 8	2022	9.50%		OGE	Yes	Jan 3, 2023 $450M, 10 Yr. at 5.4%
11	El Paso Electric	TX	Sep. 15	2022	9.35%		JP Mrgn Chase TII Fund	Private	
12	Kingsport Power	TN	Oct. 25	2022	9.50%		American Electric Power	Yes	Feb 27, 2023 $850M, 10 Yr. at 5.625%
13	Commonwealth Edison	IL	Nov. 17	2022	7.85%		Exelon	Yes	Jan 3, 2023 $975M, 10 Yr. and 30 Yr at 4.9% & 5.3%
14	NSTAR Electric	MA	Nov. 30	2022	9.80%		Eversource	Yes	May 8, 2023 $1.8Bil. 3Yr, 5Yr., 10Yr at 4.75% to 5.45%
15	Ameren Illinois	IL	Dec. 1	2022	7.85%		Ameren	Yes	May 2023 $500M 10 Yr. at 4.95%
16	Delmarva Power & Light	MD	Dec. 14	2022	9.60%		Exelon	Yes	Jan 3, 2023 $975M, 10 Yr. and 30 Yr at 4.9% & 5.3%
17	Duke Energy Ohio	OH	Dec. 14	2022	9.50%		Duke	Yes	March 2023 $750M 10 Yr & 30 Yr at 5.25% & 5.65%
18	Pacificorp	OR	Dec. 16	2022	9.50%		Berkshire Hathaway Energy	Yes	May 15, 2023 $1.2Bil. 31 Yr at 5.5%
19	Pudget Sound Energy	WA	Dec. 22	2022	9.40%		Alberta Investment Mgt. Co.	Private	
20	Wisconsin Public Service	WI	Dec. 22	2022	9.80%		WEC Energy	Yes	Jan. 9, 2023 - $1.1 B; 3 and 5 Yr. at 4.75
21	Sierra Pacific Power	NV	Dec. 27	2022	9.56%		Berkshire Hathaway Energy	Yes	
22	Empire District Electric	OK	Dec. 29	2022	9.30%		Algonquin Power & Utilities	Foreign	
23	Wisconsin Electric Power	WI	Dec. 29	2022	9.80%		WEC Energy	Yes	Jan. 9, 2023 - $1.1 B; 3 and 5 Yr. at 4.75
24	**Average 2022 ROE Awarded under 9.9%**				**9.29%**				

_____

Notes for pages 1 and 2

* All ROE data from Regulatory Research Associates & excludes Limited Issue Rider cases

** A summary of all ROEs including those at 9.9% and above is included on page 3 of this exhibit

Electric Rate Case Return on Equity (ROE) Rates (2022 and 2023)*

ROEs Under 9.9%**

Line	Electric Company	Jurisdiction	Order Date		ROE Awarded in 2022	ROE Awarded in 2023	Parent Company	Pub. Finan'ls Avail.	Long Term Debt Issued Since Date of Rate Order
1	Minnesota Power Enterpr.	MN	Jan. 23	2023		9.65%	Allete	Yes	Apr. 27, 2023 $125M 10 Yr. at 4.9%
2	Cheyenne Light Fuel & Pwr.	WY	Jan. 26	2023		9.75%	Black Hills	Yes	Sep. 15, 2023 $$450M 10.5 Yr. at6.15%
3	Duke Energy Progress	SC	Feb. 9	2023		9.60%	Duke Energy	Yes	Mar. 2023 $500M (10 Yr), $500M (30 Yr.) at 5.25% & 5.35%
4	Southwestern Electric Power	LA	Feb. 17	2023		9.50%	Xcel Energy	Yes	Jul. 31, 2023, $800M 10 Yr at 5.45%
5	Oncor Elec. Delivery	TX	Mar. 9	2023		9.70%	Sempra Energy	Yes	Jun. 2023 $550M (3 Yr), $700M (10 Yr.) at 5.4% & 5.5%
6	Versant Power	ME	May. 31	2023		9.35%	Enmax (City of Alberta, Can.)	Private	
7	Northern States Power	MN	Jun 1	2023		9.25%	Xcel Energy	Yes	Jul. 31, 2023, $800M 10 Yr at 5.45%
8	Central Maine Power	ME	Jun 6	2023		9.35%	Avangrid	Yes	
9	MDU Resources	ND	Jun 6	2023		9.75%	MDU Resources	Yes	
10	Consolidated Edison of NY	NY	Jul. 20	2023		9.25%	Consolidated Edison	Yes	Nov 2023 $600M (10 Yr.) at 5.5%
11	Northern Indiana P. S.	IN	Aug. 2	2023		9.80%	NIPSCO	Yes	Jun 2024 $600M (5 Yr) at 5.2%
12	Entergy Texas	TX	Aug. 3	2023		9.57%	Entergy	Yes	May 2024 $1.2B (30 Yr.) at 7.125%
13	Duke Energy Progress	NC	Aug. 18	2023		9.80%	Duke Energy	Yes	Sep. 2023 $600M (10 Yr), $750M (30 Yr.) at 5.75% & 6.10%
14	Green Mountain Power	VT	Aug. 23	2023		9.58%	Eniger	Private	
15	United Illuminating Group	CT	Aug. 25	2023		8.63%	Avangrid	Yes	Oct. 2023 $65M 10 Yr. 4.5% (Remarketed)
16	Tuscon Electric Power	AZ	Aug. 25	2023		9.55%	Fortis	Canada	
17	Avista	ID	Aug. 31	2023		9.40%	Avista	Yes	
18	Public Service of Colorado	CO	Sep. 6	2023		9.30%	Xcel Energy	Yes	Feb 2024 $800M (10 Yr.) at 5.5%
19	MDU Resources	MT	Sep. 21	2023		9.65%	MDU Resources	Yes	
20	Duke Energy KY	KY	Oct. 12	2023		9.75%	Duke Energy	Yes	Jun 2024 $1.5B (10 Yr & 30 Yr) at 5.45 & 5.80
21	New York State Elec. & Gas	NY	Oct. 12	2023		9.20%	Avangrid	Yes	
22	Rochester Gas & Electric	NY	Oct. 12	2023		9.20%	Avangrid	Yes	
23	Potomac Edison	MD	Oct. 18	2023		9.50%	Exelon	Yes	Feb 2024 $1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
24	Southwestern Public Service	NM	Oct. 19	2023		9.50%	Xcel Energy	Yes	Feb 2024 $800M (10 Yr.) at 5.5%
25	NorthWestern Energy Group	MT	Oct. 25	2023		9.65%	NorthWestern Energy Group	Yes	
26	Madison Gas & Electric	WI	Nov. 3	2023		9.70%	MGE Energy	Yes	
27	Public Service of Oklahoma	OK	Nov. 3	2023		9.30%	American Electric Power	Yes	Jun 2024 $1.0B (30 Yr.) 7%
28	Northern States Power	WI	Nov. 9	2023		9.80%	Xcel Energy	Yes	Feb 2024 $800M (10 Yr.) at 5.5%
29	Wisconsin Power & Light	WI	Nov. 9	2023		9.80%	Alliant Energy	Yes	
30	Atlantic City Electric	NJ	Nov. 17	2023		9.60%	Exelon	Yes	Feb 2024 $1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
31	Pacificorp	WY	Nov. 28	2023		9.35%	Berkshire Hathaway	Yes	
32	Empire District Electric	AR	Dec. 7	2023		9.70%	Algonquin Power & Utilities	Canada	
33	Ameren Illinois	IL	Dec. 14	2023		8.72%	Ameren	Yes	
34	Baltimore Gas & Electric	MD	Dec. 14	2023		9.50%	Exelon	Yes	Feb 2024 $1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
35	Commonwealth Edison	IL	Dec. 14	2023		8.91%	Exelon	Yes	Feb 2024 $1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
36	Portland General Electric	OR	Dec. 18	2023		9.50%	Portland General Electric	Yes	
37	Nevada Power	NV	Dec. 26	2023		9.52%	Berkshire Hathaway	Yes	
38	Idaho Power	ID	Dec. 28	2023		9.60%	IDACORP	Yes	
39	**Average 2023 ROE Awarded under 9.9%**					**9.48%**			

Summary of All Cases (incl. ROEs at 9.9% and Above)*

Line	Caption/No. of Cases	State	Company	ROE % * 2022	ROE % * 2023	2022	2023	Explanations & Commentary
1	**Number of ROE Decisions Under 9.9%**					23	38	From Pages 1 and 2
2	**ROEs Awarded at 9.90% or Higher**							
3		Michigan	DTE Electric	**9.90%**	**9.90%**	1	1	
4			Consumer Energy Co.		**9.90%**		1	
5			Upper Peninsula Power		**9.90%**		1	
6		Ohio	Dayton Power & Light	**10.00%**		1		Distribution ROE Only; Smaller Utility (536K customers)
7		N. Carolina	Duke Energy Carolinas		**10.10%**		1	
8		Georgia	Georgia Power	**10.50%**		1		Troubled Nuclear Plant Construction
9		Alaska	Alaska Elec. Light & Power		**11.45%**		1	Small Juneau Alaska utility (17,600 customers)**
10		California	Pacific Gas & Electric	**10.70%**	**10.70%**	1	1	Wild Fire Risk
11		California	Pacific Gas & Electric	**10.00%**		1		Wild Fire Risk
12		California	San Diego Gas & Electric	**10.20%**	**10.65%**	1	1	
13		California	San Diego Gas & Electric	**9.95%**		1		
14		California	So. California Edison	**10.30%**	**10.75%**	1	1	Wild Fire Risk
15		California	So. California Edison	**10.05%**		1		Wild Fire Risk
16		California	Pacificorp		**10.00%**		1	
17		California	Liberty Utilities (CalPeco Elec.)		**10.00%**	-	1	Small Utility - Lake Tahoe (Rate Base of Approx. $350M)***
18	Total Cases with ROEs Stated (Excl. Lmtd. Issue Riders)					**32**	**48**	
19	**Avg. ROE Rate Awarded**		**Excluding 9.9% Plus Cases**			**9.29%**	**9.48%**	
20			**All Cases***			**9.54%**	**9.66%**	**Simple 2 Yr. Average** **9.6%**

* All ROE data from Regulatory Research Associates & excludes Limited Issue Rider cases
** Per page 24 of Avista Form 10-K filed in early 2023.
*** Per Algonquin Investor Presentation of Nov. 10, 2023, page 16

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-21534
Exhibit AG-32
July 26, 2024

2022-2023 Midwest ROE Decisions Outside Michigan*

Line	Company	State Jurisdiction	Month	Year	2023 Authorized ROE Decision
	(a)	(b)	(c)	(d)	(e)
1	Minnesota Power	Minnesota	January	2023	9.65%
2	Northern States Power	Minnesota	June	2023	9.25%
3	Northern Indiana P.S.	Indiana	August	2023	9.80%
4	Duke Energy Kentucky	Kentucky	October	2023	9.75%
5	Madison Gas & Electric	Wisconsin	November	2023	9.70%
6	Northern States Power	Wisconsin	November	2023	9.80%
7	Wisconsin Power & Light	Wisconsin	November	2023	9.80%
8	Ameren Illinois	Illinois	December	2023	8.72%
9	Commenwealth Edison	Illinois	December	2023	8.91%
10	**Average of 2022 and 2023 Decisions**				**9.49%**

* As published by Regulatory Research Associates

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-21534
Exhibit AG-33
July 26, 2024

Comparison of AG and DTEE Peer Groups

			Elimination Factors										
		2023	Revs. Over Under				Reorg.	EPS	OS Wind	Large NU Ops	Total	Peer Group per	
Line	Value Line Electric Utilities	Revs. ($M)	20 B +	1 B	No Div. Grth	Foreign	M & A	Fall-Off	& Wldfr.	& DTE	Factors	AG	DTEE
1	AVANGRID	$ 8,309			Yes		Yes				2		
2	Consolidated Edison	14,663										x	
3	Dominion Energy	14,393			Yes		Yes				2		
4	Duke Energy	29,060	Yes								1		x
5	Eversource Energy	11,911					Yes		Yes		2		
6	Exelon	21,727	Yes								1		x
7	FirstEnergy	12,870					Yes				1		
8	NextEra Energy	28,114	Yes							Yes	2		x
9	PPL Corp.	8,312						Yes			1		
10	Public Service Enterp. Group	11,237										x	x
11	Southern Co.	25,253	Yes								1		x
12	ALLETE	1,880					Yes				1		x
13	Alliant Energy	4,027										x	x
14	Ameren	7,500										x	x
15	American Electric Power	18,882					Yes				1		x
16	CMS Energy	7,462										x	x
17	CenterPoint Energy	8,646					Yes				1		x
18	DTE Energy	12,745								Yes	1		
19	Entergy	12,147					Yes	Yes			2		x
20	Fortis	11,517				Yes					1		
21	Evergy	5,508						Yes			1		x
22	MGE Energy	670		Yes							1		x
23	OGE Energy	2,674						Yes			1		x
24	Otter Tail	1,349								Yes	1		x
25	WEC Energy	8,893					Yes				1		x
26	Avista	1,752										x	x
27	Black Hills	2,331										x	x
28	Edison International	16,338							Yes		1		x
29	Hawaiian Electric	3,682			Yes			Yes	Yes		3		
30	IDACORP	1,766										X	x
31	Northwestern	1,422										x	x
32	PNM Resources	1,939										x	
33	Pacific Gas & Electric	24,438	Yes						Yes		2		
34	Pinnacle West Capital	4,696						Yes			1		x
35	Portland General Electric	2,923						Yes			1		
36	Sempra Energy	16,720				Yes					1		x
37	Xcel Energy	14,206							Yes		1		x
38	Unitil	557		Yes							1		
	Totals		5	2	3	2	9	7	5	3	**36**	**10**	**25**

Companies Eliminated from Peer Group Consideration
(due to M & A, Reorg. and EPS Growth Disruptions)

Line	Company involved in M & A, Reorg.	Anticipated Actions to be Taken per Value Line
1	Avangrid	Iberdola of Spain looking to acquire remainder of Company
2	Dominion Energy	Selling various assets to reduce debt
3	Eversource	Looking to sell Off-Shore Wind and Water Distribution assets
4	First Energy	Selling $3.5 Billion in Transmission Assets
5	Allete*	Being acquired by Global Infrastructure Partners
6	American Electric Power*	Selling AEP OnSite Partners for $0.3 billion
7	CenterPoint Energy*	Sale of two gas units pending for $1.2 B to Bernhard Capital Ptns.
8	Entergy*	Looking to sell shut-down nuclear assets
9	WEC Energy*	Purchasing $0.5 billion stake in Texas solar project

		EPS per Value Line				
	mpany with Earnings Disruption	2020	2021	2022	2023	ments based on Value Line and Company Docu
10	PPL Corp	$ 2.04	$ 0.53	$ 1.41	$ 1.60	Effects of Restructuring
11	Entergy*	6.90	6.87	5.35	11.10	Hurricanes Ida and Zeta (2020-22); Favorable IRS Audit Outcome (2023)
12	Evergy*		3.83	3.26	3.17	Impairment Loss in 2022
13	OGE Energy*		2.36	2.25	2.07	
14	Hawaiian Electric		2.25	2.20	1.81	Wildfires - Value Line estimates 2028 EPS at $1.00 per share
15	Pinnacle West*		5.47	4.26	4.41	Disruptive Rate Case Outcome in late 2021 - EPS to recover
16	Portland General Electric			2.74	2.38	Mild Weather in 2023 and higher costs

* These companies have been included in the Company's peer group

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case
Peer Group Market to Book Equity Ratios-Mar. 31, 2024

Case No. U-21534
Exhibit AG-34
July 26, 2024

Line	Company (a)	Ticker (b)	Mkt. Val. p/Sh. Of Com. Equity Mar.. 31, 2024* (c)	Millions: Book Value of Com. Equity** (d)	Millions: Common Shares** (e)	Book Value per Share (d) / (e) (f)	Market to Book Ratio (c) / (f) (g)
1	Alliant Energy	LNT	$ 50.40	$ 6,817	256.4	26.59	1.90
2	Ameren	AEE	73.96	11,443	266.6	42.92	1.72
3	Avista	AVA	35.02	2,521	78.2	32.24	1.09
4	Black Hills	BKH	54.60	3,334	68.9	48.39	1.13
5	CMS Energy	CMS	60.34	7,722	298.6	25.86	2.33
6	Consolidated Edison	ED	90.81	21,615	346.0	62.47	1.45
7	IDACORP	IDA	92.89	2,415	50.1	47.63	1.95
8	Northwestern	NEW	50.93	2,813	64.8	43.41	1.17
9	PNM Resources	PBM	37.64	2,356	90.2	26.12	1.44
10	Public Service Enterprise Group	PEG	66.78	15,718	497.0	31.63	2.11
11	**Average**						**1.63**

* Per Yahoo

** Per SEC Filings on Form 10-Q for quarter ended March 2024

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21534**
DTE Electric - Electric Rate Case | **Exhibit AG-35**
July 26, 2024
Page 1

Rating Agency Cash Flow Ratios
(With ROE at 9.85% and a 50% Common Equity Ratio)

		12 M.E. March 2023 Adjusted Moody's Cash Flow Ratio ($ Mil.)			
Line	Caption	Cash From Operations Pre-Wkg. Cap.	Debt	Ratio (e) / (f)	Note
	(a)	(b)	(c)	(d)	
1	**12 M.E. March 2023 Actual Ratio Results**	$ 2,290	$ 11,322	**20.2%**	1
2	Increase Common Equity (to 50% vs 47.1%)	-	(559)		2
3	Increase ROE (to 9.85% vs 9.26%)	109			3
4	**Pro Forma w/50% Common Equity, 9.85% ROE**	$ 2,399	$ 10,763	**22.3%**	L 1 + L 2 + L 3
5	**Ratings Downgrade Risk**			***Below 21%***	4

Notes

1 From page 1 of Moody's July 6, 2023 report on DTE Electric (see AGDE _____ Attachment)

2 Amount from "Rebalancing Adjustments" determined under the footnotes on this page

3 Net Income if a 9.85% ROE was earned: Common Equity of $9.779 below x 9.85% equals $ 963 M
DTE Electric 12 M.E. March net income (from Company SEC filings) 854 M
Net Income Under 9.85% **$ 109** M **To Line 3 Above**

4 From page 2 of Moody's July 6, 2023 report on DTE Electric under "Factors that could lead to a downgrade"

Avg. Capital ($Mil.) 12 M.E. March 2023 (Per SEC Filings of Company)	March 2022	March 2023	Two Point Average	Rebalancing Adjustmts.	2021 Rebalanced Amount	2021 Rebalanced % Capital
Long-Term Debt	$ 9,787	$ 10,889	$ 10,338	**$ (559)**	$ 9,779	50.0%
Preferred Stock	-	-	-		-	0.0%
Common Equity	8,827	9,613	9,220	559	9,779	50.0%
Total	$ 18,614	$ 20,502	$ 19,558		$ 19,558	100.0%
Common Equity %			**47.1%**			

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

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-21534
Exhibit AG-37
Date: July 26, 2024
Page 1 of 1

O & M Summary-Millions of Dollars

Line	Caption or Description of Item	Amount	Reference
	(a)	(b)	(c)
1	**Total O & M Per Company Case**	$ 1,267.0	Ex. A-13, Sch. C5
	AG Case Adjustments		
2	2024-25 Inflation at CPI	(14.6)	Ex. AG-38
3	Steam Generation	(21.9)	Ex. AG-39
3	Voluntary Separation Program	(10.1)	Testimony*
4	Tree Tim Program Savings	(8.8)	Ex. AG-40**
5	Discontinue Non-Residential Merchant Fee Program	(3.5)	Testimony***
6	Uncollectible Accounts Expense	(3.8)	Ex. AG-41
7	Injuries & Damages	(2.9)	Ex. AG-42
8	Active Health Care	(3.1)	Ex. AG-43
9	Supplemental Savings Plan Expense	(3.2)	Testimony
10	Corporate Aircraft	(0.3)	Testimony****
11	Incentive Compensation Plan	(51.3)	Ex. AG-44
12	Total Adjustments	**(123.5)**	Sum L2 to L11
13	**Total O&M per AG Case**	**$ 1,143.5**	L1 + L12
14	**Total O&M Reduction**	**$ (123.5)**	line 13 less Line 1

* DR AGDE 1.23c indicates 2025 savings of $20.3 million. The AG has included 50% of this amount reflecting the Company's uncertainty

** DTEE determined its O&M savings in Exhibit A-13, Sch. C5.7 from only two categories on Exhibit A-22. DR AGDE-4.167 confirms that a third category (Tree Trim Reactive) should also be included in determining the "Tree Trim Savings"

*** Amount calculated by Company and indicated on Exhibit A-13, Sch. C5.7.1.

**** Based on DR AGDE-1.24 response

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company - Electric Rate Case

Case No. U-21534
Exhibit AG-38
Date: July 26, 2024

2024 and 2025 Inflation in O&M

AG Estimate vs. Company Estimate

		Thousands of Dollars				
Line	Major O&M Area	Normalized 2023*	Inflation Rate**	AG Inflation Amount	Inflation Per Company	Inflation Difference
	(a)	(b)	(c)	(d)	(e)	(f)
1	Steam Power Generation	$ 182,951	4.65%	$ 8,507	$ 13,554	$ (5,047)
2	Fuel Supply & Merc Fuel Handling	7,507	4.65%	349	505	(156)
3	Nuclear Power Generation			-	-	-
4	PERC	27,475		-	-	-
5	All Other Expenses	133,760	4.65%	6,220	9,747	(3,527)
6	Hydraulic Power Generation	10,641	4.65%	495	623	(128)
7	Other Power Generation	26,894	4.65%	1,251	1,392	(141)
8	Distribution			-	-	-
9	Tree Trim Expenses	105,398		-	-	-
10	ADMS	150		-	-	-
11	All Other Expenses	262,099	4.65%	12,188	13,944	(1,756)
12	Customer Service			-	-	-
13	Merchant Fees	10,655		-	-	-
14	Cust. 360 Amortization	2,797		-	-	-
15	TOD Reg. Amortization	1,460		-	-	-
16	All Other Expenses	85,069	4.65%	3,956	5,935	(1,979)
17	Uncollectible Accounts Expense	37,477		-	-	-
18	Regulated Marketing			-	-	-
19	Charging Forward Amortization	1,181		-	-	-
20	All Other Expenses	19,791	4.65%	920	1,240	(320)
21	Corporate Support			-	-	-
22	Injuries & Damages	15,577		-	-	-
23	Environmental	3,762		-	-	-
24	All Other Expenses	176,604	4.65%	8,212	9,740	(1,528)
25	Pension & Benefits	86,640		-	-	-
26	Total	**$ 1,197,888**		**$ 42,097**	**$ 56,680**	**$ (14,583)**

* Per ABDE-1.6

** Reflects CPI Inflation at 2.4% and 2.2% for 2024 and 2025 per the February 1, 2024 Blue Chip Financial Forecast

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

O & M Summary-Millions of Dollars

Case No. U-21534
Exhibit AG-39
Date: July 26, 2024

Line	Caption or Description of Item	$ Millions Amount	Reference
	(a)	(b)	(c)
1	**Steam Generation per Company**	**$ 213.4**	Exh. A-13, Sch C5.1
	AG Estimate & Adjustments		
2	Actual 2023 Expense	183.0	See DR AGDE 1.6
3	2024 and 2025 Inflation at 4.65%	8.5	Note 1
4	Total 2025 Estimate per Attorney General	**191.5**	L2 + L3
5	**Total O&M Reduction**	**$ (21.9)**	L4 less L1

Note 1 Reflects CPI Inflation at 2.4% and 2.2% for 2024 and 2025 per the February 1, 2024 Blue Chip Financial Forecast

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-21534
Exhibit AG-40
Date: July 26, 2024

Tree Trim Savings ($Millions of Dollars)

Line	Cost Category or Caption	2025 Test Yr. Costs	2022 Hist. Yr. Costs	Savings from Lower 2025 Costs vs. 2022	Ex. A-22, Sch. L1
	(a)	(b)	(c)	(d)	(e)
1	Tree Trim Reactive*	$ 7.4	$ 16.2	$ 8.8	Line 4
2	Tree Trim Storm*	10.0	15.0	5.0	Line 9
3	Other DO-Service Operations Storm and Trouble*	7.5	11.3	3.8	Line 10
4	Total Costs	24.9	42.5	17.6	
5	Less Campany Savings Reflected in filed O&M Exhibit**			8.8	
6	**Additional O&M Reduction**			**$ 8.8**	

* These are the three O&M items identified by the Company in DR-4.167 (Exhibit AG-7).

** This is reflected on Exhibit A-13, Schedule C5.6 in footnote 6 and the third item.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company - Electric Rate Case

Case No. U-21534
Exhibit AG-41
Date: July 26, 2024

Uncollectible Accounts Expense

(Thousands of Dollars)

Line	Caption or Description	Net Write-Off Amounts	Net Sales	% Charged Off & AG Projection (b) / (c)	Reference
	(a)	(b)	(c)	(d)	
1	Total Year 2021	$ 40,044	$ 5,551,588	**0.721%**	See AGDE 1.27a Attchmt.
2	Total Year 2022	37,658	5,614,043	**0.671%**	See AGDE 1.27a Attchmt.
3	Total Year 2023	44,144	5,847,903	**0.755%**	See AGDE 1.27a Attchmt.
4	Avg. Percentage			**0.716%**	Avg. of Lines 1,2 & 3
5	Projected Test Year Revenues			**$ 6,399,006**	See AGDE 1.27b Attchmt.
6	**Total Uncollectible Expense per AG (Excl. Direct Charges)**			**$ 45,795**	Line 4 x Line 5
7	Average of Amounts charged to other Expenses Directly 2021-2023			1,231	See AGDE 1.27a Attchmt.
8	**AG Uncollectible Expense Forecast**			**47,026**	Line 6 + 7
9	**Uncollectible Expense per DTE Electric in 2023**			**50,870**	Ex. A-13, Sch. C5.8, line 15
10	***Decrease in Uncollectible Accounts Expense***			***$ (3,844)***	Line 8 less Line 9

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company - Electric Rate Case

Case No. U-21534
Exhibit AG-42
Date: July 26, 2024

Injuries & Damages
(Thousands of Dollars)

Line	Year or Caption (a)	Amount (b)	Notes/Sources (c)
1	2019	$ 11,042	Ex. A-13, Sch. C5.10, p. 3
2	2020	11,702	Ex. A-13, Sch. C5.10, p. 3
3	2021	32,953	Ex. A-13, Sch. C5.10, p. 3
4	2022	17,158	Ex. A-13, Sch. C5.10, p. 3
5	2023	5,029	AGDE-1.38 Attachment
6	Five Year Average	$ 15,577	Avg of 2019 to 2023
7	Company 2025 Estimate	$ 18,440	Ex. A-13, Sch. C5.10, p. 1
8	**Reduction in Injuries & Damages**	**$ (2,863)**	Line 6 less Line 7

Medical Expenses -Reduced Inflation Rate
(Thousands of Dollars)

Line	Caption	Actual Gross Expenses 2017	2018	2019	2020	2021	2022	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Historic Cost Information							
1	Gross Actual Medical, Dental & Vision	$ 69,193	$ 68,182	$ 70,419	$ 67,201	$ 84,283	$ 82,998	Note 1
2	Average Employees	6,582	6,795	6,896	6,848	6,751	6,697	Note 1
3	Cost per Employee (L1 / L2)	$ 10.512	$ 10.034	$ 10.212	$ 9.813	$ 12.485	$ 12.393	Note 1
4	Avg. Annualized Cost per Employee Increase			***3.33%***	***for 5 Yrs.***			

Line		Projected Expense 2023	2024	2025	Test Year*	
	Projected Cost Information					
5	O&M Costs for 2023 (per ABDE-1.6)	50,013		-	-	
	Less Constant Dollar Adjustment (per ABDE-1.6)	(424)				
6	Net Amount Escalated at 3.33%	49,589	51,240	52,947	52,947	Note 2
7	Company Expense Estimate				56,083	Ex. A-13, Sch. C5.11, pg. 1 (L11)
8	***Reduction in Medical Expense and O&M***				***$ (3,136)***	Line 6 less Line 7

Notes
1 Line 1, Col. (b) to (f) are from Exhibit A-13, Sched. C5.11.3 Line 4, 5 and 6
2 The 3.33% escalation per year is based upon the historical 2017 to 2022 historical experience from line 4 abov

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-21534
Exhibit AG-44
Date: July 26, 2024
Page 1 of 1

Incentive Compensation Exclusion From O&M

Line	Caption or Description of Item (a)	$Thousands Amount (b)	Reference (c)
1	Financial Metric Related Incentive Compensation	$ 39,232	Note 1
2	Operational Metrics Deferred and Subject to Later Recovery	10,663	Note 2
3	2023 Incentive Compensation in Rates Not Paid by Company	1,358	Note 3
4	Total O&M Reduction	**$ 51,253**	

1 See page 62 of witness Cooper's testimony

2 Determined as follows

Operational Metric Incentive Compensation (p. 62 of Cooper testimony	$	20,271
Portion to Defer for later recovery (100% less 47.4% per AGDE 1.48 Attach.)		52.60%
Amount to Defer ($20,771 x 52.6%)	$	10,663

3 Over-recovery of 2023 Incentive Compensation of $6.792K x 20% per Exhibit AG-WC1

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-1.23a
Respondent: M. Fix
Page: 1 of 1

Question: 23. Attachment 1 to the Company's application for rate relief show that $72 million of the rate increase pertains to Operating Costs & Other. A January 10, 2024 Detroit Free Press article reported that DTE Energy offered buyouts to about 3,000 employees or 30% of its workforce. Please provide the following information as it pertains to DTEE and any affiliates that bill the Company for costs:

a. Provide the date that this buyout offer was made to employees and how many employees were targeted.

Answer: A voluntary separation incentive package (VSIP) was offered to 1,025 DTE Electric employees and 1,622 DTE Energy Corporate Services, LLC employees (shared service employees) on January 8, 2024.

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-1.23b
Respondent: M. Fix
Page: 1 of 1

Question: 23. Attachment 1 to the Company's application for rate relief show that $72 million of the rate increase pertains to Operating Costs & Other. A January 10, 2024 Detroit Free Press article reported that DTE Energy offered buyouts to about 3,000 employees or 30% of its workforce. Please provide the following information as it pertains to DTEE and any affiliates that bill the Company for costs:

b. Provide details of the buyout offer, such as who qualified, effective date, payouts, etc.

Answer: Employees were considered eligible if they did not fall under certain criteria, including, but not limited to: represented (union) employees, engineers, operations critical employees (e.g. control room operators, cybersecurity roles). The VSIP included 25 weeks of an employee's base salary plus one additional week for every year of service up to a maximum of 44 weeks total. The effective separation date varied from February 2024 through June 2024.

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-1.23c
Respondent: M. Fix
Page: 1 of 1

Question: 23. Attachment 1 to the Company's application for rate relief show that $72 million of the rate increase pertains to Operating Costs & Other. A January 10, 2024 Detroit Free Press article reported that DTE Energy offered buyouts to about 3,000 employees or 30% of its workforce. Please provide the following information as it pertains to DTEE and any affiliates that bill the Company for costs:

c. Provide the number of total employee reductions, and by department, with related cost reductions for 2023, 2024, and 2025.

Answer: 140 DTE Electric employees and 249 DTE Energy Corporate Services, LLC employees accepted the VSIP. The package was not offered in 2023. There are no projected savings for 2024 due to DTE Electric's actual costs of the program (the accrued separation payments) of $30.6 million. A primary purpose of the VSIP was to realign the workforce to support the changing nature of the Company's work and how we do it, such as an increased focus on infrastructure investments, cybersecurity, and the clean energy transition. Because of this, DTE Electric is still evaluating potential 2025 cost reductions due to the need to fill key roles so that we can continue our progress towards building more modern infrastructure and a future with lower carbon emissions. Currently, DTE Electric estimates that up to $20.2 million in expense reductions could materialize in 2025, inclusive of both labor and employee benefits. This estimate will continue to evolve due to the need to fill many key roles. This savings estimate also does not include any offset of the program costs. If actual savings are realized in 2025, they will be embedded in the Company's rates as actual costs in a future rate case.

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-1.23d
Respondent: M. Fix
Page: 1 of 1

Question: 23. Attachment 1 to the Company's application for rate relief show that $72 million of the rate increase pertains to Operating Costs & Other. A January 10, 2024 Detroit Free Press article reported that DTE Energy offered buyouts to about 3,000 employees or 30% of its workforce. Please provide the following information as it pertains to DTEE and any affiliates that bill the Company for costs:

d. Provide the cost reductions in subpart (c) separately for labor cost savings, savings in employee benefits, space, and other overhead costs for each year and the projected test year.

Answer: Estimated labor expense savings in 2025 are $14.4 million and estimated savings in benefits expense for 2025 are $5.8 million. The estimated benefits savings presumes a continuation of the deferral mechanisms for pension and OPEB. There are no expected savings for space or other overheads.

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-1.23e
Respondent: N. Foley
Page: 1 of 1

Question: 23. Attachment 1 to the Company's application for rate relief show that $72 million of the rate increase pertains to Operating Costs & Other. A January 10, 2024 Detroit Free Press article reported that DTE Energy offered buyouts to about 3,000 employees or 30% of its workforce. Please provide the following information as it pertains to DTEE and any affiliates that bill the Company for costs:

e. Identify in which exhibit and line number in this rate case the cost savings are shown for each department, or overall, for each year 2023- 2025, and for the projected test year, and the specific amount.

Answer: There are no costs or projected savings related to the VSIP in any of the Company's exhibits.

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-1.28d
Respondent: P. Bennett
Page: 1 of 1

Question: 28. Refer to page 2 of Exhibit A-13, Schedule C5.7.1, on Credit/Debit Card Merchant Fees. Please:

d. Provide a comparison in Excel of the transaction fees incurred under each payment method used by customers, such as payment by check, automatic bank withdrawal, Kiosks, etc., for each year 2021, 2022, and 2023.

Answer: The table below indicates the associated fees by payment channel for 2021-2023

Average Fee by Payment Channel

	2021	2022	2023
Electronic Funds Transfer (EFT)	$0.08	$0.08	$0.10
Automatic Clearing House (ACH)	$0.09	$0.09	$0.11
Check	$0.20	$0.20	$0.20
KIOSK	$4.95	$3.65	$3.92

Attachment: U-21534 AGDE-1.28d Other Payment Transaction fees. xls

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-1.28g
Respondent: P. Bennett
Page: 1 of 1

Question: 28. Refer to page 2 of Exhibit A-13, Schedule C5.7.1, on Credit/Debit Card Merchant Fees. Please:

g. Explain any limitations on the use of credit/debit cards by non- residential customers and when that practice began and why.

Answer: At the same time the popularity of credit cards was on the rise with business owners, Large Industrial and Commercial customers who previously were prevented from utilizing a card payment had the ability to use this payment type in the new SAP system. In August of 2019, the Company began mitigating merchant fees with a rate blocking policy for large commercial and industrial customers since these customers were not intended to use this payment method.

The Company further limited usage of credit cards for business customers with over $75,000 in annual usage beginning in 2021.

Attachment: None

MPSC Case No: U-21534
Requester: AG
Question No.: AGDE-1.24
Respondent: T. Uzenski
Page: 1 of 1

Question: 24. Please provide the cost of privately-hired corporate jet airplane travel by DTEE employees, DTE Energy employees, and other affiliated companies, charged to DTEE and included in the historical costs for 2022, 2023, and the projected test year. Provide also a list of the employees who used such private jet travel for each year 2022 and 2023, their position title, the date of travel, the individual trip cost, the reason for the travel, the cities visited, the miles traveled round trip, and the tons of CO2 carbon footprint for each trip identified in the Company's Net-Zero Sustainability Report or similar report. Provide this information in Excel.

Answer: The Company leases a fractional share of an aircraft for limited business travel by executives (typically Vice President & above) and other employees when there is an appropriate business need.

The costs of private (non-commercial) corporate jet expense charged to DTE Electric for 2022 and 2023 was $236,299 and $139,026, respectively. There is approximately $258,000 of corporate jet expenses included in the projected test period.

Refer to the attachment for a list of employees who utilized private jet travel in 2022 including their positions, dates of travel, trip costs, business reason for travel, and the departure and destination cities. The Company does not track the miles traveled or CO2 emissions. There was no corporate jet travel in 2023.

Attachment: U-21534 AGDE-1.24 2022 Corporate Jet Travel.xlsx

DTE Electric Company
Case No. U-21534
AGDE-1.24
2022 Corporate Jet Travel Details

Business Purpose	DESTINATION	DEPARTURE	RETURN	PASSENGERS	Total Cost
National LAMPAC meeting, EEI Spring Board Meeting and Congressional visits	Washington DC (one way flight)	3/7/2022 (Willow Run Airport)	Commercial flight for return	Gerard Anderson - Chairman of Board of Directors	$ 6,811
2022 DTE Annual Shareholders Meeting/Board and Committee Meetings	Pick up at Concord NC, Hartsfied-Jackson Atlanta, GA, Final destination Fort Lauderdale, FL	5/3/2022 (Oakland County International Airport)	One Way Trip	Matt Paul - DTE Electric President & COO David Ruud - Executive VP & CFO Ruth Shaw - DTE Board of Directors David Thomas - DTE Board of Directors Valerie Williams - DTE Board of Directors	$ 21,356
2022 DTE Annual Shareholders Meeting/Board and Committee Meetings	Fort Lauderdale, FL	5/3/2022 (Oakland County International Airport)	5/5/2022 Fort Lauderdale to Oakland Cnty Intl	Gerard Anderson - Chairman of Board of Directors Trevor Lauer - DTE Vice Chairman Chip McClure - DTE Board of Directors Jerry Norcia - Chief Executive Officer JoAnn Chavez - Senior VP and Chief Legal Officer Joi Harris - President & COO - DTE Energy Mark Murray - DTE Board of Directors Lisa Muschong - VP Corporate Secretary Renee Tomina - Senior VP, Project Management Office Gary Torgow** - DTE Board of Directors Robert Skaggs** - DTE Board of Directors ** Return Flight Only	$ 62,516
RETURN FROM 2022 DTE Annual Shareholders Meeting/Board and Committee Meetings	Fort Lauderdale, FL to Hartsfied-Jackson, Atlanta, GA to Concord Regional, Concord, NC to Oakland County Intl.	5/5/2022 Fort Lauderdale, FL	5/5/2022 Plane returned to Oakland Cnty Intl	Diane Antishin - VP Human Resources Lisa Muschong - VP Corporate Secretary Matt Paul - DTE Electric President & COO David Ruud - Executive VP & CFO Ruth Shaw - DTE Board of Directors David Thomas - DTE Board of Directors Renee Tomina - Senior VP, Project Management Office	$ 10,796
Meeting with sell side analysts and various investors at the AGA conference	Miami, FL	5/16/2022 Oakland Cnty Intl	One Way Trip	Jerry Norcia - Chief Executive Officer David Ruud - Executive VP & CFO Barbara Tuckfield - Director, Investor Relations	$ 16,991
RETURN FROM: Meeting with sell side analysts and various investors at the AGA conference	Return to Oakland Cnty. Intl.	5/18/2022 - Miami, FL	return to Oakland County Airport	Jerry Norcia - Chief Executive Officer David Ruud - Executive VP & CFO Barbara Tuckfield - Director, Investor Relations	$ 6,846
Attend 2022 Mackinac Policy Conference	Mackinac Island, MI	6/1/2022 - Oakland County Intl.	One Way Trip	Joi Harris - President & COO - DTE Energy Renze Hoeksema - VP, Corporate & Government Affairs Trevor Lauer - DTE Vice Chairman Jerry Norcia - Chief Executive Officer Shawn Patterson - VP Environmental Mgmt & Safety	$ 2,854
	Oakland Cnty Intl. (return from Mackinac)	6/2/2022 - Mackinac Island, MI	One Way Trip - returned to Oakland Cnty Intl.	Joi Harris - President & COO - DTE Energy Renze Hoeksema - VP, Corporate & Government Affairs Trevor Lauer - DTE Vice Chairman Jerry Norcia - Chief Executive Officer Shawn Patterson - VP Environmental Mgmt & Safety	$ 7,427
Jerry Norcia Attend the INPO Board meeting in the morning, then Jerry, Pete and Trevor will meet with INPO team in the afternoon for a DTE/INPO CEO meeting	Atlanta GA	7/13/2022 Oakland Cnty Intl to Fulton County, Atlanta GA	7/14/2022 Fulton county, Atlanta, GA to Oakland Cnty Intl	Pete Dietrich - Senior VP & Chief Nuclear Officer Trevor Lauer - Dte Vice Chairman Jerry Norcia - Chief Executive Officer	$ 14,583

DTE Electric Company
Case No. U-21534
AGDE-1.24
2022 Corporate Jet Travel Details

	Meeting with sell side analysts and various investors during Guggenheim NDR	Teterboro, NJ	8/8/2022 Oakland Cnty Intl to Teterboro, NJ	8/8/2022 Teterboro, NJ to Oakland Cnty Intl	Jerry Norcia - Chief Executive Officer Barbara Tuckfield - Director, Investor Relations	$ 11,445
	Meeting in NY under a tight time schedule, with several employees. Recent travel using commercial airlines has been erratic; need to have the flexibility to get everyone there on time and return on time. Meet with the CeO & team at GE in NY to discuss stator, relationship, schedule, extended power upgrade wind repowering, and CCUS capabilities.	New York, NY	8/22/2023 Oakland Cnty Intl to Schenectady County, NY	8/23/2022 Schenectady County, NY to Oakland Cnty Intl.	Dennis Decator - Manager, Nuclear Project Portfolio Steven Fatora - Director, Nuclear Project Management Trevor Lauer - DTE Vice Chairman Jaspreet Singh - Vice President, Corporate Services Renee Tomina - Senior VP, Project Management Office	$ 11,585
	The DTE Team and a team from the Nature Conservancy (TNC) will go to the UP to tour federally protected wilderness areas, visit sustainable forestry practices, and learn about the preservation and conservation efforts and carbon program	Marquette, MI	8/29/2022 Oakland Cnty to Sawyer Intl, Marquette MI	8/29/2022 Sawyer Intl, Marquette MI to Oakland Cnty Intl.	Joi Harris - President & COO - DTE Energy Jerry Norcia - Chief Executive Officer Shawn Patterson - VP Environmental Mgmt & Safety Patrick Doran (The Nature Conservancy) Helen Taylor (The Nature Conservancy) Rich Tuzinsky (The Nature Conservancy)	$ 8,560
	September DTE Energy Board Strategic Meeting and Committee Meetings bring outside directors here	Bring Directors to Detroit Metro Airport	9/20/2022 Depart Hartsfield-Jackson, Atlanta GA, to Carrollton, GA to Detroit Metro to Oakland Cnty Int.	One Way Trip	David Thomas - DTE Board of Directors Ruth Shaw - DTE Board of Directors	$ 11,832
	September DTE Energy Board Strategic Meeting and Committee Meetings bring outside directors here	Bring Directors to Detroit Metro Airport	9/20/2022 Depart Houston, TX to Detroit Metro then Oakland Cnty Intl.	One Way Trip	Valerie Williams - DTE Board of Directors	$ 15,841
	September DTE Energy Board Strategic Meeting and Committee Meetings outside directors return home	Raleigh-Durham Intl, Morrisville, NC	9/22/2022 Depart Oakland Cnty Intl, to Detroit Metro to Raleigh Durham Intl	One Way Trip	Ruth Shaw - DTE Board of Directors	$ 6,058
	September DTE Energy Board Strategic Meeting and Committee Meetings outside directors return home	Knoxville, TN Houston, TX	9/22/2022 Depart Oakland Cnty Intl, to Detroit Metro to Knoxville, TN then to Houston TX	One Way Trip	Gail McGovern - DTE Board of Directors Valerie Williams - DTE Board of Directors	$ 17,966
	Attend INPO Board meetings and CEO Conference	Atlanta, GA	11/1/2022 Depart Oakland Cnty Intl to Atlanta GA	11/2/2022 Atlanta, GA to Oakland Cnty Intl	Jerry Norcia - Chief Executive Officer Pete Dietrich (return flight only) - Senior VP and Chief Nuclear Officer	$ 12,923

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

Exhibit: AG-48
Case No: U-21534
July 26, 2024

Computation of Revenue Deficiency for Projected Test Year 2025

($000)

Line	Description	Company Filed Amount	AG Recommended Adjustments	Revised Amount
	(a)	(b)	(c)	(d)
1	Rate Base [1]	$ 22,107,989	$ (783,950)	$21,324,039
2	Rate of Return	5.92%	-0.25%	5.67%
3	Income Required	$ 1,309,478	$ (100,405)	$ 1,209,073
4	Adjusted Net Operating Income [2]	1,087,100	127,821	1,214,921
5	Income Deficiency (Sufficiency)	$ 222,378	$ (228,226)	$ (5,848)
6	Revenue Multiplier	1.3496	1.3496	1.3496
7	**Revenue Deficiency (Sufficiency)**	300,129	$ (308,021)	(7,892)
8	Return On - Tree Trim Surge Program	18,786	(8,886)	9,900
9	Return On - Monroe Regulatory Asset	137,518	-	137,518
10	**Revenue Deficiency (Sufficiency) - Total**	**$ 456,433**	**$ (316,907)**	**$ 139,526**

[1] Rate Base Adjustments Exhibit AG-18

[2] AG adjustments to Operating Income - Increase (Decrease):

			Source
Sales Revenue			
O&M Expenses		123,500	Exhibit AG-37
Property Tax		12,261	Exhibit AG-18
Depreciation Expense		40,788	Exhibit AG-18
Total		$ 176,549	
Effective Tax Rate (1-1/1.3496)	25.91%		
Taxes		(45,737)	
Interest Synchronization on Capital Adjustments		(2,992)	RevDef-WP1
Adjusted Net Operating Income		$ 127,821	

PROOF OF SERVICE - U-21534

The undersigned certifies that a copy of the ***Attorney General's Testimony and public 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 26th day of July 2024.

Joel B. King Digitally signed by Joel B. King Date: 2024.07.26 17:07:12 -04'00'

Joel B. King

MPSC Staff:
Lori Mayabb
Monica Stephens
Michael Orris
Heather Durian
Amit Singh
mayabbl@michigan.gov
stephensm11@michigan.gov
orrism@michigan.gov
durianh@michigan.gov
singha9@michigan.gov

ALJ:
Hon. Sally Wallace
Wallaces2@michigan.gov

Attorney General of Michigan:
Joel King
Kingj38@michigan.gov
ag-enra-spec-lit@michigan.gov

Sebastian Coppola
sebcoppola@corplytics.com

DTE Electric Company:
Jon Christinidis
Andrea Hayden
Paula Johnson-Bacon
John Janiszewski
Breanne Reitzel
Jon.christinidis@dteenergy.com
Andrea.hayden@dteenergy.com
Paula.bacon@dteenergy.com
John.janiszewski@dteenergy.com
Breanne.reitzel@dteenergy.com
mpscfilings@dteenergy.com

Soulardarity/We Want Green, Too:
Amanda Urban
Mark Templeton
Jacob Schuhardt
Madison Wilson
Samuel Heppell
t-9aurba@lawclinic.uchicago.edu
templeton@uchicago.edu
jschuhardt@uchicago.edu
madisonwilson@uchicago.edu
heppell@uchicago.edu
aelc_mpsc@lawclinic.uchicago.edu

ELPC/Union of Concerned Scientists, Inc./Vote Solar/The Ecology Center:
Daniel Abrams
Nicholas Wallace
Michael Oliva
dabrams@elpc.org
nwallace@elpc.org
moliva@fosterswift.com

MEC/Sierra Club/NRDC/CUB:
Tracy Jane Andrews
Christopher Bzdok
tjandrews@tropospherelegal.com
chris@tropospherelegal.com

The Kroger Company:
Kurt Boehm
Jody Kyler Cohn
kboehm@bkllawfirm.com
jkylercohn@bkllawfirm.com

EVgo Services, LLC:
Nikhil Vijaykar
Michael Oliva
nvijaykar@keyesfox.com
moliva@fosterswift.com

Electrify America:
Stephen Bright
Jennifer Morante
Krystal Hermiz
Steve.bright@electrifyamerica.com
jmorante@grsm.com
khermiz@grsm.com

City of Ann Arbor/MMAUI:
Valerie Jackson
Valerie Brader
vjackson@a2gov.org
valerie@rivenoaklaw.com

MEIBC/Foundry Association/Energy Michigan/Advanced Energy United/Institute for Energy Innovation:
Timothy Lundgren
Laura Chappelle
Justin Ooms
tlundgren@potomaclaw.com
lchappelle@potomaclaw.com
jooms@potomaclaw.com

ABATE:
Stephen Campbell
scampbell@clarkhill.com

Michigan Cable Telecommunications Association:
Sean Gallagher
sgallagher@fraserlawfirm.com

International Transmission Company:
Richard Aaron
Olivia Flower
Hannah Buzolits
Courtney Kissel
raaron@dykema.com
oflower@dykema.com
hbuzolits@dykema.com
ckissel@dykema.com

PROTEC:
Michael Watza
Mike.watza@kitch.com

Walmart, Inc.:
Melissa Horne
mhorne@hcc-law.com

GLREA:
Don Keskey
Brian Coyer
donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com

Utility Workers Union of America, Local 223:
Benjamin King
bking@michworkerlaw.com