STATE OF MICHIGAN
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May 19, 2022

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

Dear Ms. Felice:

Re: **MPSC Case No. U-20836**

Enclosed find the ***Attorney General's PUBLIC Testimony and Exhibits of Sebastian Coppola and Dr. David Dismukes,*** and related Proof of Service.

Sincerely,

Joel B. King

Digitally signed by Joel B. King
Date: 2022.05.19 14:03:29 -04'00'

Joel B. King
Assistant Attorney General

cc: All Parties

PROOF OF SERVICE - U-20836

The undersigned certifies that a copy of the ***Attorney General's PUBLIC Testimony and Exhibits of Sebastian Coppola and Dr. David Dismukes*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 19th day of May 2022.

Joel B. King Digitally signed by Joel B. King Date: 2022.05.19 14:08:49 -04'00'

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-20836

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

May 19, 2022

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I. Introduction

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

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

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. I have testified in several regulatory proceedings before the Michigan Public Service Commission (MPSC or Commission) and other regulatory jurisdictions. I have prepared and/or filed testimony in rate case proceedings, revenue decoupling reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power Supply Cost Recovery (PSCR) cases, 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, operation 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 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 Consumers Energy Company (CECO) 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed rebuttal testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2020-2021 GCR plan reconciliation case No. U-20554.
- 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 Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2020-2021 GCR plan reconciliation case No. U-20552.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utility Corporation (MGUC) 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (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 Gas Company (SEMCO) 2021-2022 GCR plan case No. U-20822.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMLC) 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

- o Filed testimony on behalf of the Michigan Attorney General in CECo 2021 PSCR plan case No. U-20802.
- o Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR reconciliation case No. U-20234.
- o 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.
- o Filed testimony on behalf of the Michigan Attorney General in CECo 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- o Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- o Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- o Filed testimony on behalf of the Michigan Attorney General in SEMCO 2020-2021 GCR plan case No. U-20551.
- o Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2020 electric rate Case No. U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- o 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.
- o Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- o Filed testimony on behalf of the Michigan Attorney General in DTE Gas (DTE Gas) 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- o 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.

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 AG to perform an independent analysis of DTE Electric Company's ("Company" or "DTEE") Electric Rate Case filing U-20836. 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 Electricity Sales & Revenue
2. The level of Operations and Maintenance expenses
3. Incentive Compensation
4. The level of proposed Rate Base and Capital Expenditures
5. The Company's Cost of Capital
6. The Adjusted Revenue Deficiency

The absence of a discussion of other matters in my testimony should not be taken as an indication that I agree with those aspects of 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-1.1 DTE Energy Investor Presentation Information
2. Exhibit AG-1.2 Contingency Capital Expenditures

3. Exhibit AG-1.3 Inflation Factors
4. Exhibit AG-1.4 Distribution Cap. Ex. Historical Capital Expenditures,
5. Exhibit AG-1.5 Distribution Cap. Exp.- Historical Strategic Capital Program
6. Exhibit AG-1.6 Distribution Suppliers & Material Expanded Lead Times
7. Exhibit AG-1.7 Distribution Underground Line Relocation Pilot Project
8. Exhibit AG-1.8 ADMS Components Original Cost Forecast
9. Exhibit AG-1.9 ADMS-DMS/OMS Current Cost Forecast
10. Exhibit AG-1.10 SOC and ASOC Project Delay and Cost Overrun
11. Exhibit AG-1.11 Tree Trimming Surge Program Cost Savings
12. Exhibit AG-1.12 Accountability for SAIDI Goals Not Achieved
13. Exhibit AG-1.13 Power Generation Capital Projects Not Fully Authorized
14. Exhibit AG-1.14 Generation Projects Not Authorized Disallowance
15. Exhibit AG-1.15 MPSC Guidance on Pilot Projects
16. Exhibit AG-1.16 Hydrogen Pilot Project Fuel and CO2 Generated
17. Exhibit AG-1.17 Slocum BESS Cost of Capacity
18. Exhibit AG-1.18 CONF Blackstart Assets Improvement
19. Exhibit AG-1.19 BWEC Covid-10 Costs Not Supported
20. Exhibit AG-1.20 Nuclear Plant Security Video System
21. Exhibit AG-1.21 ACPP/TOU Pilot Costs
22. Exhibit AG-1.22 Customer Pre-Pay Project Information
23. Exhibit AG-1.23 Digital Product Teams Projects
24. Exhibit AG-1.24 Corporate Facilities Renovations
25. Exhibit AG-1.25 Corporate Energy Center Project Cost Overrun
26. Exhibit AG-1.26 Capital Expenditures and Rate Base Disallowances
27. Exhibit AG-1.27 Overall Cost of Capital
28. Exhibit AG-1.28 Cost of Common Equity-Summary
29. Exhibit AG-1.29 Cost of Common Equity-DCF
30. Exhibit AG-1.30 Cost of Common Equity-CAPM
31. Exhibit AG-1.31 Cost of Common Equity-Risk Premium
32. Exhibit AG-1.32 Electric ROE Decisions by Regulatory Commissions

33. Exhibit AG-1.33 Peer Group Analysis
34. Exhibit AG-1.34 Market to Book Ratios
35. Exhibit AG-1.35 Moody's Cash Flow Coverage Ratio
36. Exhibit AG-1.36 Value Line Article on Volatility vs. Risk
37. Exhibit AG-1.37 DTEE Mobility Sales Wedge Data
38. Exhibit AG-1.38 Residential Sales Revenue Adjustment
39. Exhibit AG-1.39 Residential Sales Analysis
40. Exhibit AG-1.40 O&M Adjustments Summary
41. Exhibit AG-1.41 Distribution O&M 2020 Adjustment
42. Exhibit AG-1.42 Tree Trimming Surge O&M Cost Reductions
43. Exhibit AG-1.43 Customer Service Employee Growth and Costs
44. Exhibit AG-1.44 Uncollectible Expense Adjustment
45. Exhibit AG-1.45 Merchant Fee Adjustment
46. Exhibit AG-1.46 Merchant Fees Information from DTEE
47. Exhibit AG-1.47 Health Care Expense Adjustment
48. Exhibit AG-1.48 DTEE Response – Pension Asset Mix
49. Exhibit AG-1.49 DTEE Incentive Measures Achieved
50. Exhibit AG-1.50 Calculation of Return on Tree Trimming Surge Costs
51. Exhibit AG-1.51 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 $388.2 million. This rate increase represents an overall increase in rates of 7.5%, with an 8.8% 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 $59.8 million. Based on this amount of rate increase, the average residential customer should see an increase of approximately 1.3% in their total bill.

It is noteworthy to point out that for the historical test year, the Company reported a revenue excess of $111.7 million and earned a return on common equity of 10.1%, which is above the authorized ROE rate of 9.9%.

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

1. I propose higher residential sales for $52.7 million of additional revenue.
2. I propose a lower level of Operations and Maintenance expenses of $112.1 million for the test year.
3. I propose a reduction in capital expenditures of $929.1 million and a reduction in rate base of $679.9 million for a reduction in revenue requirement of $48.3 million.
4. I propose a reduction in depreciation expense of $28.0 million pertaining to the proposed reductions in capital expenditures.
5. I recommend an authorized rate of return on equity of 9.5% in comparison to the Company's proposed ROE rate of 10.25%, for a reduction in the revenue deficiency of $85.0 million.
6. I recommend that the Commission reiterate its previous order that deferred tree trimming costs accumulate interest at the short-term borrowing interest rate and not the overall cost of capital as proposed by the Company.

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

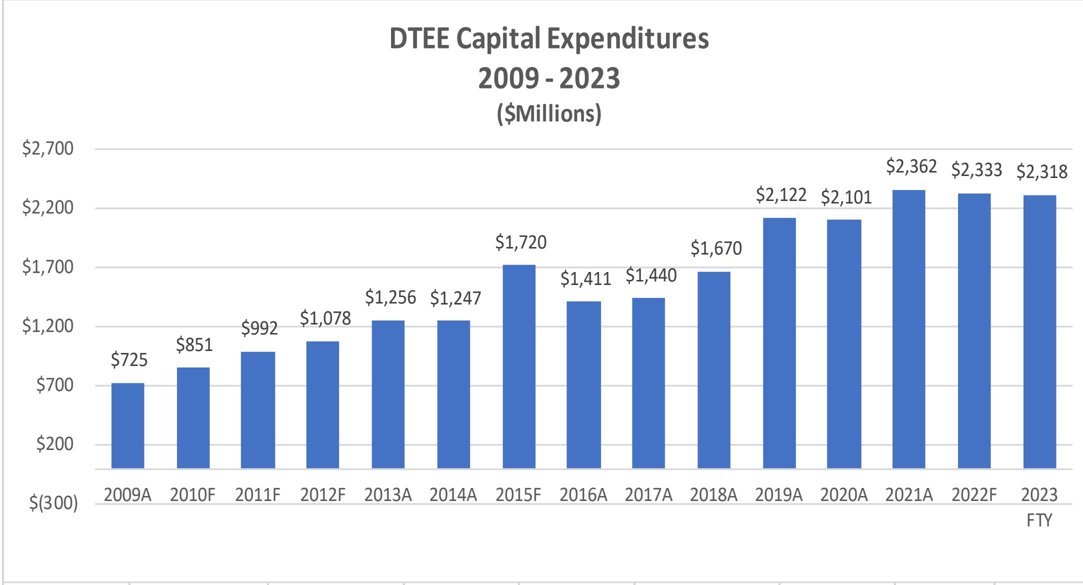
III. LARGE INCREASE IN RATE BASE AND CAPITAL EXPENDITURES

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 $2.3 billion for 2021, $1.944 billion for the 10 months ending October 2023 ($2.3 billion annualized), and an additional $2.3 billion for the 12 months ending October 2023. The total proposed capital expenditures over this 34-month period are nearly $6.5 billion. These expenditures follow capital expenditures of $4.2 billion made during the prior two years in 2019 and 2020.[1] The following chart in Table 1 shows the dramatic increase in capital expenditures over recent years, in comparison to more moderate amounts in prior years.

[1] DTEE response to AGDE-9.311a.

Table 1



Until 2011, the Company was able to keep capital expenditures below $1 billion annually. Ten years later, the level of annual capital expenditures has more than doubled.

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 15%, to $21.3 billion. The proposed level of rate base in this rate case is more than double the amount of rate base the Company had 10 years ago.

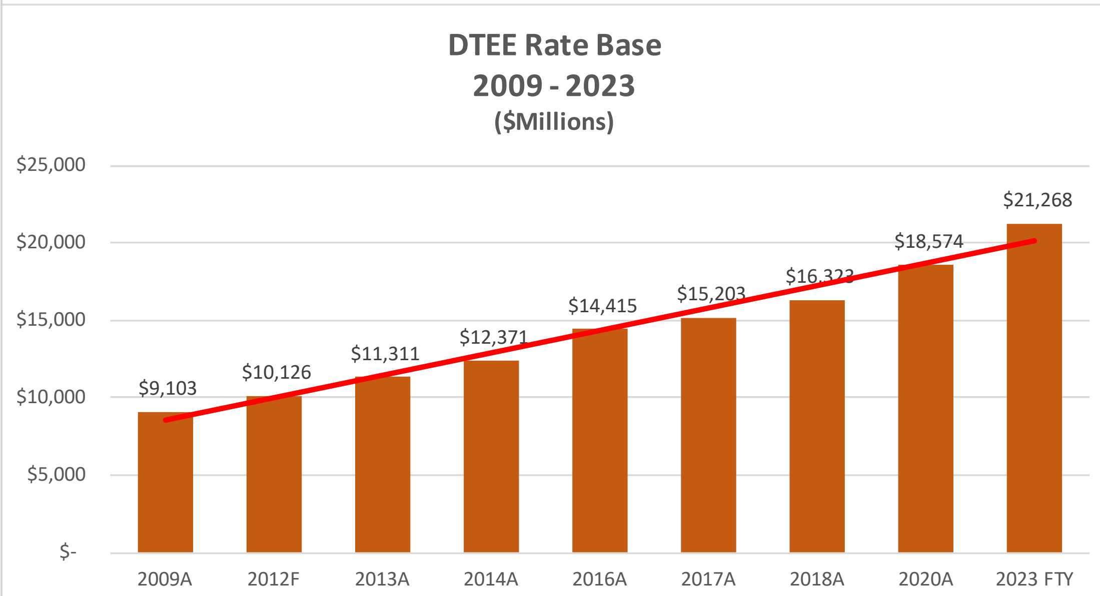
Table 2
DTE Electric Rate Base Growth
2009 to Projected 2023 Test Year

Rate Base Year	2009A	2012F	2013A	2014A	2016A	2017A	2018A	2020A	2023 FTY
Docket No.	U-16472	U-16472	U-17767	U-18014	U-18255	U-20162	U-20561	U-20836	U-20162
Rate Base [1] (Millions)	$ 9,103	$ 10,126	$ 11,311	$ 12,371	$ 14,415	$ 15,203	$ 16,323	$ 18,574	$ 21,268
Year over Year Change		11%	12%	9%	17%	5%	7%	14%	15%
Cumulative Change over 2009 Rate Base		11%	24%	36%	58%	67%	79%	104%	134%

[1] Historical actual rate base in each docket, except 2012 and 2023 FTY are proposed amounts.

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, a control center, information technology projects, and office remodeling that raise questions about priority spending toward more fundamental electrical infrastructure projects.

The Company also seems to be experiencing moderate customer growth in its market area. However, moderate customer growth has existed in prior years. 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 since 2011.

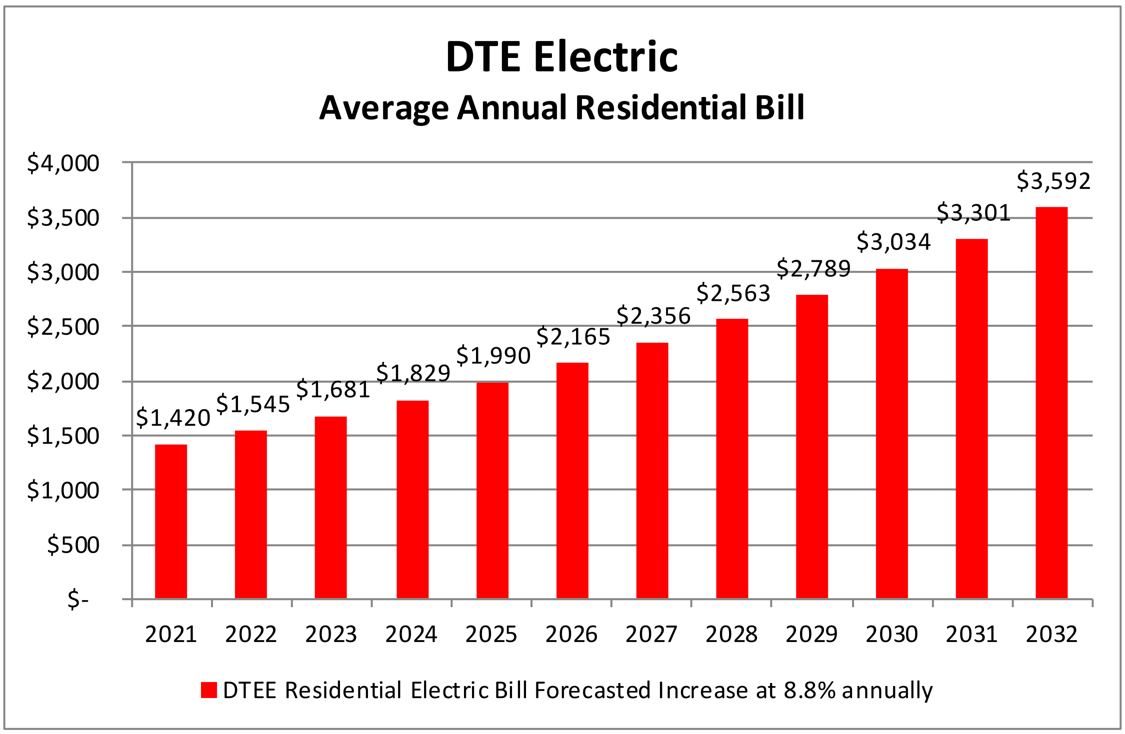
Second and perhaps a bigger driver, the replacement of aging electrical infrastructure has given the Company an opportunity to accelerate rate base growth in order to increase earnings growth. For utility companies, earnings growth is directly related to rate base growth. As shown in the tables above, 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-1.1 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. HAVE YOU DETERMINED WHAT THE IMPACT ON RESIDENTIAL CUSTOMER BILLS COULD BE OVER THE COMING YEARS IF THE COMMISSION APPROVES THE PROPOSED RATE INCREASE AND THAT RATE OF INCREASE CONTINUES INTO FUTURE YEARS?

A. Yes. The Company has proposed to increase residential rates in this rate case by 8.8%. If we assume that the Company continues on the current pace of capital expenditures with annual rate cases and rate increases, the average residential total annual electric bill in 11 years will nearly triple, from $1,420 in 2021 to $3,592 in 2032.[2] Table 4 below shows the potential increase in the average residential electric bill if the current trend in rate base growth continues and power generation costs remain the same.

Table 4



This potential escalation in annual customer bills would pose a significant burden on all residential customers, and especially those with fixed and low income. In addition, this dramatic potential increase in residential bills does not take into consideration potential increases in power generation costs and further escalations in capital expenditures. As the

[2] Current average electric bill in 2021 of $1,420 = Total Residential revenue of $2,892,516,000 divided by 2,036,578 residential customers per Exhibit A-16, Schedule F2, page 2 and DR AGDE-2 8. Current bill escalated at 8.8% per year through 2032.

Company transitions from generation of power from coal to more expensive renewable sources, such as wind and solar, or natural gas with more volatile fuel prices, total electric bills could significantly exceed the levels shown in Table 4. Should power generation costs increase significantly in the coming years, customers may run into even greater bill affordability problems.

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 likely 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 2022 and 2023, 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 rounded inflation factors are 3.50% for

2022 and 2.60% for 2023. These rates reflect the increase in the forecasted Consumer Price Index during 2022-2023 as shown in the Blue Chip Financial Forecast issued on February 2, 2022.[3] These inflation rates are slightly higher than the Company's proposed rates in Exhibit A-13, Schedule C5.15.

A. Contingent Capital Expenditures

The Company has disclosed that it has included total contingency costs of $2,100,000 in its forecasted capital expenditures for the 10 months ending October 2022, and for the 12 months ending October 2023, pertaining to the Time of Use rate implementation project. Exhibit AG-1.2 includes the discovery responses supporting this amount as provided by the Company.

In the Company's prior rate cases, including Case No. U-20561, the Commission addressed this issue and determined that contingency amounts should be excluded from capital expenditures and rate base. The Commission similarly affirmed this exclusion in its orders in Case Nos. U-20162, U-18255, U-18124, U-18014, U-17999, U-17990, U-17767 and U-17735.

The fact that these added costs are contingent means that they may not be spent in whole or in part. Despite the Company's claim that the amounts may be spent, it does not mean that these costs belong in rate base. It is not fair or reasonable for the Company to recover

[3] Exhibit AG-1.3 includes the pertinent page of the Blue Chip Report with the forecasted Consumer Price Index for 2022 and 2023 by quarter.

the depreciation expense and the return on the investment on potential costs that may not be actually incurred but have been added to rate base.

Therefore, I recommend that the Commission exclude the $2,100,000 from the forecasted capital expenditures in this rate case filing.

B. Distribution Plant

As shown on page 1 of Exhibit A-12, Schedule B5.4, the Company has forecasted nearly $3.8 billion in capital expenditures for the 34 months ending October 2023 for additions to Distribution Plant. After reviewing the testimony of Company witness Sharon Pfeuffer, Morgan Elliott-Andahazy, related exhibits, and responses to discovery, I have identified capital expenditure reductions applicable to several areas.

1. Emergent Replacements

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

A. On page 1 of Exhibit A-12, B5.4, the Company has identified three categories of Emergent Replacement Programs: Storm-related, Non-Storm and Substation Reactive. The total amount of capital expenditures for 2020 for these three programs was $344.4 million. The Company has forecasted $612.1 million in capital expenditures for 2021, $309.8 million for the 10 months ending October 2022, and $371.7 million for the 12 months ending

October 2023. After reviewing historical spending levels in these areas and recent trends, I find the Company's forecasted capital expenditures to be reasonable.

However, the Company arrived at its forecasted level of expenditures for emergent replacement programs by applying retroactive inflation adjustments to historical amounts and labeling them normalization adjustments on page 2 of Exhibit A-12, Schedule B5.4. I do not agree with that approach, as I stated in my testimony on this matter in Case No. U-20561. My acceptance of the Company's overall capital expenditures forecast for the emergent replacement programs should not be taken as an acceptance of the Company's methodology to arrive at those forecasted amounts.

2. Major Equipment

Q. PLEASE PROVIDE YOUR ASSESSMENT OF FORECASTED CAPITAL EXPENDITURES FOR MAJOR EQUIPMENT UNDER THE ELECTRIC SYSTEM EQUIPMENT CATEGORY.

A. On page 4 (line 24) of Exhibit A-12, B5.4, the Company shows forecasted capital expenditures of $12,550,000 for 2021, $18,950,000 for the 10 months ending October 2022,[4] and $23,290,000 for the 12 months ending October 2023. According to Ms. Pfeuffer's direct testimony, the Company calculated the forecasted amount by using 2020 actual results and applied its inflation factors for future periods.[5] The use of a single year

[4] Exhibit A-12, Schedule B5.4, page 4, lines 5 and 23, columns (f) – (c).
[5] Sharon Pfeuffer direct testimony at page 153.

to base a forecast is often a poor methodology, given that expenditures can vary significantly from year to year. For this capital item, the amount spent in 2020 is the highest amount spent during the past five years from 2017 to 2021. The most recent capital expenditures amount of $13,594,000 in 2021 is the second lowest amount spent in the most recent five years and reflects a decline of 37% from the amount spent in 2020. Exhibit AG-1.4 includes discovery response AGDE-6.192a with the actual amount spent in this area from 2017 to 2021.

As shown in the schedule in Exhibit AG-1.4, the level of spending has been volatile from year to year during the 2017-2021 period. In these circumstances, the best approach is to use a five-year average amount to establish a spending base to forecast future capital expenditures. The five-year average amount of capital spending for the 2017-2021 period is $15,253,000. To forecast the capital expenditures for the 10 months ending October 2022, I applied the inflation factor of 3.5% to the base amount of $15,253,000 to calculate the 2022 full year capital expenditures of $15,784,000. The amount for the 10 months ending October 2022 is $13,153,000 ($15,784,000 x 10/12).

For the 12 months ending October 2023, I used the same approach starting with the base amount of $15,253,000 multiplied for 10 months of inflation at 2.92% (3.50 x 10/12) through October 2022 and then the inflation rate of 2.6% for 2023 to arrive at the amount of $16,107,000.[6]

[6] $15,253,000 x 1.0292 x 1.026 = $16,107,000.

Based on my calculations, the Company's capital expenditures forecast of $18,950,000 for the 10 months ending October 2022 needs to be adjusted down by $5,797,000 ($13,153,000 – $18,950,000) and the 12 months ending capital expenditures of $23,290,000 need to be reduced by $7,183,000 ($16,107,000 - $23,290,000).

Therefore, I recommend that the Commission remove the $5,797,000 and $7,183,000 from the Company's forecasted capital expenditures for the applicable periods.

3. NRUC & Improvement Blankets[7]

Q. PLEASE PROVIDE YOUR ASSESSMENT OF FORECASTED CAPITAL EXPENDITURES FOR NRUC AND OTHER FACILITY IMPROVEMENTS.

A. On page 5 (line 33) of Exhibit A-12, B5.4, the Company shows forecasted capital expenditures of $22,138,000 for 2021, $25,412,000 for the 10 months ending October 2022,[8] and $31,322,000 for the 12 months ending October 2023. According to Ms. Pfeuffer's direct testimony, the Company calculated the forecasted amount by using 2020 actual results and applied its inflation factors for future periods.[9] In her testimony, she also stated that she added an additional $2.0 million in costs in the 2022 and 2023 forecasts

[7] NRUC = Normal retirement unit change-out for routine equipment replacements. Blanket Orders for smaller facility improvements. Page 158 of Sharon Pfeuffer's direct testimony.
[8] Exhibit A-12, Schedule B5.4, page 4, lines 5 and 23, columns (f) – (c).
[9] Sharon Pfeuffer direct testimony at page 153.

to reflect higher costs of projects.[10] No further explanation was provided as to which projects would incur higher costs in those years or why.

As stated earlier, the use of a single year to base a forecast is often a poor methodology, given that expenditures can vary significantly from year to year. For this capital item, the amount spent of $27.2 million in 2020 is the highest amount spent during the past five years from 2017 to 2021. In 2021, capital spending declined to $22.9 million. In prior years from 2017 to 2019 spending has ranged from $15.8 million to $21.6 million. Exhibit AG-1.4 includes discovery response AGDE-6.193a with the actual amount spent in this area from 2017 to 2021.

As shown in the schedule in Exhibit AG-1.4, the level of spending has been volatile from year to year during the 2017-2021 period. In these circumstances, the best approach is to use a five-year average amount to establish a spending base from which to forecast future capital expenditures. For the five-year period from 2017 to 2021, the average amount of capital sending was $21,064,000. To forecast the capital expenditures for the 10 months ending October 2022, I applied the inflation factor of 3.5% to the base amount of $21,064,000 to calculate the 2022 full year capital expenditures of $21,801,000. The amount for the 10 months ending October 2022 is $18,168,000 ($21,801,000 x 10/12).

For the 12 months ending October 2023, I used the same approach starting with the base amount of $21,064,000 multiplied for 10 months of inflation at 2.92% (3.50 x 10/12)

[10] *Id*. page 152.

through October 2022 and then the inflation rate of 2.6% for 2023 to arrive at the amount of $22,243,000.[11]

Based on my calculations, the Company's capital expenditures forecast of $25,412,000 for the 10 months ending October 2022 needs to be adjusted down by $7,244,000 ($18,168,000 – $25,412,000) and the 12 months ending October 2023 capital expenditures of $31,232,000 need to be reduced by $8,990,000 ($22,243,000 - $31,232,000).

Therefore, I recommend that the Commission remove the $7,244,000 and $8,990,000 from the Company's forecasted capital expenditures for the applicable periods.

4. General Plant, Tools and Equipment

Q. PLEASE PROVIDE YOUR ASSESSMENT OF FORECASTED CAPITAL EXPENDITURES FOR GENERAL PLANT, TOOLS AND EQUIPMENT.

A. On page 5 (line 37) of Exhibit A-12, B5.4, the Company shows forecasted capital expenditures of $7,387,000 for 2021, $7,079,000 for the 10 months ending October 2022,[12] and $8,700,000 for the 12 months ending October 2023. According to Ms. Pfeuffer's direct testimony, the Company calculated the forecasted amount by using 2020 actual results and applied its inflation factors for future periods.[13]

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[11] $21,064,000 x 1.0292 x 1.026 = $22,243000.
[12] Exhibit A-12, Schedule B5.4, page 4, lines 5 and 23, columns (f) – (c).
[13] Sharon Pfeuffer direct testimony at page 153.

This is another situation where the use of a single year to base a forecast is a poor methodology, given the variability in spending from year to year. For this capital item, the amount spent of $8.0 million in 2020 is the highest amount spent during the past five years from 2017 to 2021. In 2021, capital spending declined to $5.7 million. In prior years from 2017 to 2019 spending has ranged from $4.0 million to $5.9 million. Exhibit AG-1.4 includes discovery response AGDE-6.193a with the actual amount spent in this area from 2017 to 2021.

As shown in the schedule in Exhibit AG-1.4, the level of spending has been volatile from year to year during the 2017-2021 period. In these circumstances, the best approach is to use a five-year average amount to establish a spending base from which to forecast future capital expenditures. For the five-year period from 2017 to 2021, the average amount of capital spending was $5,684,000. To forecast the capital expenditures for the 10 months ending October 2022, I applied the inflation factor of 3.5% to the base amount of $5,684,000 to calculate the 2022 full year capital expenditures of $5,883,000. The amount for the 10 months ending October 2022 is $4,907,000 ($5,883,000 x 10/12).

For the 12 months ending October 2023, I used the same approach starting with the base amount of $5,684,000 multiplied for 10 months of inflation at 2.92% (3.50 x 10/12) through October 2022 and then the inflation rate of 2.6% for 2023 to arrive at the amount of $6,002,000.[14]

[14] $5,684,000 x 1.0292 x 1.026 = $6,002,000.

Based on my calculations, the Company's capital expenditures forecast of $7,079,000 for the 10 months ending October 2022 needs to be adjusted down by $2,177,000 ($4,907,000 – $7,079,000) and the 12 months ending capital expenditures of $8,700,000 need to be reduced by $2,698,000 ($6,002,000 - $8,700,000).

Therefore, I recommend that the Commission remove the $2,177,000 and $2,698,000 from the Company's forecasted capital expenditures for the applicable periods.

5. Strategic Capital Programs

Q. PLEASE PROVIDE YOUR ASSESSMENT OF THE COMPANY'S PROPOSED CAPITAL EXPENDITURES FOR STRATEGIC CAPITAL PROGRAMS.

A. On page 1 of Exhibit A-12, Schedule B5.4, the Company shows the three major capital programs under Strategic Capital Programs. The total amount of capital expenditures for the three programs was $307.6 million in 2020, and is forecasted at $355.5 million for 2021, $580.4 million for the 10 months ending October 2022, and $797.8 million for the 12 months ending October 2023. The total amount of proposed spending in these three programs over the forecasted 34 months is $1.8 billion.

The Company's proposed spending for 2022 and 2023 represents a dramatic escalation in each of the subprograms within this major program. For the full year 2022, the Company's proposed spending of $696.5 million represents more than a doubling of the capital expenditures incurred in 2020 and a 94% increase over the forecasted spending for 2021.

Similarly, the proposed spending level of $797.8 million for the 12 months ending October 2023 represents an increase of 122% over the forecasted spending in 2021.

This dramatic increase in spending over a short period of time is concerning for several reasons. First, the large escalation in spending will have a detrimental impact on customers by increasing rate base and ultimately customer rates. Second, the Company has struggled in the past to meet the amount of forecasted capital expenditures for the overall program. In Table 6 on page 20 of her direct testimony, Ms. Pfeuffer shows that for 2020 the Company had planned to spend $379.5 million for Strategic Capital Programs and only spent $307.6 million, a shortfall of 19%. Similarly, in the Company's prior rate case (Case No. U-20561), on page 16 of his direct testimony, Company witness Bruzzano included the same Table 6, which compared the amount spent on Distribution capital programs in 2018 versus the amount that the Company had proposed and received funding for in Case No. U-20162. The table shows that, in total for the three Strategic Capital Programs, the Company underspent the projected amount by $126.2 million, or 31% less than it had forecasted. In the testimony of both Mr. Bruzzano and Ms. Pfeuffer, the Company stated that the main reason for the underspending was due to the need to reassign capital and other resources to Emergent Replacement Programs as a result of major storms. Although in 2021 the Company was able to meet the forecasted capital spending level of $355.6 million by actually spending $358.9 million, the program had been scaled back from the $379.5 million forecasted in 2020.[15] Therefore, the Company's track record about its

[15] Exhibit A-121, Schedule B5.4, page 1, and Exhibit AG-1.5 (DR AGDE-6.191).

ability to meet large increases in capital expenditures for strategic capital programs remains questionable.

Third, in response to discovery, the Company reported that since the beginning of the fourth quarter of 2021 it has experienced supply chain difficulties in procuring materials, which has delayed work on some projects in distribution operations. These delays are expected to continue through the end of the second quarter of 2023. Lead times for transformers, wire, cable, and pole top hardware have quadrupled in some cases, with the most concerning being the lead time on transformers increasing from 3 months to more than 12 months currently.[16] Under these circumstances, achieving the 2021 level of capital spending on the strategic programs would be a challenge. Attempting to double the size of the programs in 2022 and 2023 would seem even more challenging and unreasonable.

Fourth, the doubling of capital spending on the programs will also require more employees and contractors. Businesses have been struggling to find and retain qualified personnel in a very tight labor market. The doubling of the capital spending means the number of labor resources, whether Company's employees or contractors, will likely need to double. In the current labor market, the availability of those additional resources is questionable and if found will require higher wages, and higher labor and contractor costs, placing added strain on the capital budgets. For the same amount of labor, the Company would be paying more and ultimately accomplish less within the same capital budget.

[16] Exhibit AG-1.6 includes DR STDE-1.79.

In summary, the Company's doubling of the capital expenditures for the strategic programs is ill-timed and unreasonable.

Q. WHAT AMOUNT OF CAPITAL EXPENDITURES DO YOU PROPOSE FOR 2022 AND 2023 FOR THE STRATEGIC CAPITAL PROGRAMS?

A. In my analysis of historical spending by the Company on strategic capital programs from 2017 to 2021, I have determined that over this time period the average annual growth rate has been approximately 20%. The overall program spending grew from $181.7 million in 2017 to $280 million in 2018, for a 54% increase. In 2019, the overall program spending grew an additional 12%, to $313.3 million. For 2020, the program spending declined by nearly 2%, to $307.8 million. In 2021, the total spending increased to $358.9 million, representing a 17% increase. Exhibit AG-1.5 provides this information.

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

Based on the 20% program growth rate from the 2021 actual spending level, I forecasted a 2022 capital spending program of $430,706,000. After adjusting for forecasted inflation, the 2022 amount is $445,781,000. For the 10 months ending October 2022, the forecasted capital expenditures are $371,484,000. In comparison, the Company has forecasted $580,391,000, which represents an excess amount of $208,907,000 over the amount I have proposed.[17]

For the 12 months ending October 2023, using the same 20% annual growth rate and adjusting for forecasted inflation, I calculated total capital expenditures of $545,770,000.[18] In comparison, the Company forecasted capital spending of $797,767,000 for an excess amount of $251,997,000 over the forecast I developed.

I recommend that the Commission accept the proposed spending levels that I calculated and remove $208,907,000 of capital expenditures for the 10 months ending October 2022 and $251,997,000 for the 12 months ending October 2023.

Q. ARE THERE SPECIFIC PROJECTS WITHIN THE COMPANY'S PROPOSED CAPITAL EXPENDITURES FOR STRATEGIC CAPITAL PROGRAMS THAT THE COMMISSION SHOULD REMOVE?

A. Yes. I have identified four major projects within strategic capital programs where costs for 2022 and 2023 should be removed or significantly reduced. These capital expenditure reductions will help the Company achieve a 20% annual total program growth rate along

[17] $358,922,000 x 1.20 = $430,706,000 x 1.035 = 445,781,000 x 10/12 = 371,484,000 – 580,391,000 = $208,907,000.

[18] $358,922,000 x 1.20 x 1.20 x 1.0292 (3.5% x 10/12) x 1.026 = $545,770,000 – 797,767,000 = $251,997,000.

with deferral of other projects that the Company may not want to undertake for 2022 and 2023 in order to stay within the lower spending level.

The four projects are strategic undergrounding pilots, ADMS-NMS expansion, ADMS-DMS/OMS delays, and ESOC project cost overruns. I will discuss each of them below.

Strategic Undergrounding Pilots – Beginning on page 113 of her direct testimony, Ms. Pfeuffer discusses the pilot program that the Company started in 2019 to assess the ability and cost of relocating overhead electrical lines in densely populated neighborhoods to below ground. The Company spent $306,000 in 2021 and plans to spend $20.7 million in 2022 and $40 million in 2023 on the existing pilot project, with plans to initiate at least one more pilot. The capital expenditures for the 10 months ending October 2022 are $17.3 million and for the 12 months ending October 2023 are $36.8 million.[19]

From Ms. Pfeuffer's direct testimony and responses to discovery, it is evident that the Company has experienced significant issues and higher costs than it had anticipated when it began the first pilot program in 2019. For example, the Company has not been able to obtain approval from nearly half of the 60 customers in the target area to relocate their services below ground. The Company also ran into more dense vegetation than it had expected and large removal of trash and debris in the work area.[20] It appears that the Company did not obtain pre-approval from customers before proceeding with the pilot

[19] Exhibit A-12, Schedule B5.4, page 10, line 10. For 10 months ending October 2022 the amount was calculated by subtracting column (c) from column (f).
[20] Exhibit AG-1.7 includes DR AGDE-6.189a, c, and d.

project and did not adequately scope the work required to complete the project. The Company considers these difficulties as lessons learned.

However, it is perplexing why the Company would proceed with the pilot program without first ensuring that the vast majority of the affected customers were interested in having their electrical lines placed underground and without written approval to do so. The Company now wants to spend up to $60 million over the two years from 2022-2023 to repeat nearly the same process on one other identified location (Fairmount DC1593) and another location yet to be determined. [21] It is not clear what additional lessons will be learned from the new pilot projects that the Company has not already learned from the first project. In response to discovery question AGDG-6.190, Ms. Pfeuffer could not identify any new learnings that the Company was seeking to garner from other pilot projects and repeated the basic goals of undergrounding electrical lines.[22] In addition, it appears that the Company has not done sufficient research with other utilities around the country who have gone through the undergrounding process to understand the difficulties, costs, and workable approaches taken by them. This information would probably be even more valuable than poorly organized pilot projects.

Given the experience with the first undergrounding pilot project and the lack of clarity as to what the additional pilot projects would achieve, I recommend that the Commission not approve the Company's proposed capital spending of $17.3 million for the 10 months

[21] Id. includes DR STDE-18.3a, 18.3bic, and 18.3bv.
[22] Id. includes DR AGDE-6.190.

ending October 2022 and the $36.8 million for the 12 months ending October 2023. If the Commission approves my recommended reduction in capital spending for the overall strategic capital programs discussed above, there is no need for the Commission to remove any capital expenditures for the undergrounding pilots.

However, if the Commission decides to approve the level of capital spending for the strategic capital programs proposed by the Company or approves an amount well above the 20% growth rate I proposed, I recommend that the Commission disallow $17.3 million of capital expenditures for the 10 months ending October 2022 and the $36.8 million for the 12 months ending October 2023.

In either case, the Commission should instruct the Company to better define what specific information it desires to gather from additional pilot projects and also improve their design, scope, and execution to achieve maximum effectiveness. The Commission should make it clear that recovery of costs pertaining the undergrounding pilots will be critically evaluated in the Company's next rate case.

ADMS-NMS – Beginning on page 3 of her direct testimony, Ms. Morgan Elliot Andahazy discusses the Advanced Distribution Management System (ADMS) and the three major component systems that make up the larger system. The component systems are Generation Management System (GMS) and Energy Management System (EMS), the Outage Management System (OMS) and Distribution Management System (DMS), and the Network Management System (NMS). The total original cost to install the three component systems was $115.6 million, based on the information presented by the Company in Case No. U-20162.[23] The Commission approved capital spending of $83 million in that rate case, which allowed the Company to proceed with implementation of the overall ADMS project.

In the current rate case, the Company reported that it has already completed the installation of the GMS/EMS and the NMS components of the system. However, in her direct testimony, Ms. Elliot Andahazy discusses the Company's decision to expand the NMS component system to included additionally functionality at a projected cost of $6.3 million. She also discusses delays and cost overruns experienced with the DMS/OMS component.

Q. WHAT IS YOUR ASSESSMENT OF THE NMS EXPANSION PROJECT?

A. With regard to the additional functionality and spending increase of $6.3 million proposed by the Company, it is not clear what the additional data requirements are and what incremental value will be generated by the additional functionality. The Company spent $17.5 million to gather supposedly high-quality system data and now states that it should have gathered more data but cannot clearly define what that data is.[24] In discovery, the Company was asked in several discovery questions to clearly identify the additional data it seeks to include in the NMS and the value of that data. The discovery responses do not

[23] Exhibit AG-1.8 includes DR AGDE-7.201.
[24] Morgan Elliot Andahazy direct testimony at page 12.

add any more light or specific information about the additional data that the Company wants to gather now.[25]

Additionally, the Company now seems to want to add new functionality and features to the system that it did not find necessary in the initial scope of the project. The additional features seem to be advanced planning tools, digital maps, and diagrams to display sections of the distribution grid. It is perplexing why, if these features are valuable, they were not included the original scope of the project. In discovery, the Company was asked to provide a copy of the cost/benefit analysis to show that the additional $6.3 million in capital spending was economically justified. The Company answered that it had not calculated the direct financial benefits of this project and referenced two other discovery responses.[26] In discovery responses STDE-4.4d and 4.1a, the Company stated it would need 12 employees to manage the data if the NMS expansion was not done. There were no details provided to support that conclusion.

The Company has failed to adequately justify the additional proposed spending of $6.3 million for expansion of the NMS. In direct testimony and responses to discovery, the Company has not made a compelling and convincing case that the additional $6.3 million of capital expenditures are warranted. Therefore, I recommend that the Commission remove the amount of $2,334,000 for the 10 months ending October 2022 and $2,883,000

[25] Exhibit AG-1.8 includes DR AGDE-7.204a, b, and e; 7.205a, b, and e.
[26] Id. includes DR AGDE-7.205c.

for the 12 months ending October 2023 for the forecasted capital expenditures in this rate case.

<u>ADMS-DMS/OMS</u> – Beginning on page 16 of her direct testimony, Ms. Elliot Andahazy discusses the current state of the OMS/DMS component of the ADMS and the delays and cost overruns experienced with this project. The cost of this project is expected to mushroom to $91.8 million, from the initial cost estimate of $67.4 million.[27] The new cost projection is $24.4 million, or 36%, higher than initially forecasted. The $91.8 million also includes $6.9 million for work to be done to the Clicksoft system that the Company claims would have been done later but is being accelerated to allow at least a partial implementation of OMS/DMS system until the Compass portion is completed.

As to the time delay for the implementation of the OMS/DMS system, according to Ms. Elliott Andahazy's direct testimony, the Company planned to implement multiple phases of the project between late 2020 and the end of 2021. The Company now expects to complete implementation by the end of 2022.[28] The Company blames the late delivery of the Compass software portion of the system and the seemingly incomplete first working test version from vendor OSI, Inc, for the project delay. The Company also blames Covid-19 restrictions in 2020 for prolonging the timeline.[29]

[27] Exhibit AG-1.9 includes DR AGDE-7.207 showing the $91.8 million. Exhibit AG-1.8 shows the $67.4 million in DR AGDE-7.201.
[28] Morgan Elliott Andahazy's direct testimony at page 16.
[29] Id. at page 17.

Q. WHAT IS YOUR ASSESSMENT OF THE OMS/DMS PROJECT?

A. Most of problems with the project delays and cost overruns for the OMS/DMS project are the result of the Company's decision to proceed with implementation of this system knowing that the OSI's OMS products were still relatively new and their Compass mobile solution was still under development.[30] Nevertheless, the Company proceeded with contracting with OSI and later discovered that OSI could not meet its obligations. The Company's reasoning with proceeding with OSI is that no other vendor offered a full suite of mature products. This was a high-risk decision and proved to be detrimental. In my direct testimony in Case No. U-20162, I stated:

> [N]o other utility in the country has yet implemented the full ADMS suite of systems. A handful of utilities have implemented some of the subsystems. Therefore, the Company is an early adopter of a new technology with all the problems and drawbacks that come with being an early adopter. Being an early adaptor of new technology has risks. It is best to learn from the mistakes of others and implement technology that is proven, and in use for a few years with minimum failures. The Company has not presented sufficient evidence that the technology it wants to implement has had a consistent and sufficient record of success. The planned implementation of the ADMS over the next three years seems premature…Based on the foregoing analysis, I have concluded that the Company's initiation of the ADMS is premature and risky with insufficient cost/benefit justification. Therefore, I recommend that the Commission disallow recovery of the projected capital expenditures for this project….[31]

The Company insisted that it could accomplish the proposed project and convinced the Commission to approve the proposed spending in that case. My testimony in Case U-20162 proved to be accurate, that as an early adopter of the ADMS system the Company

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[30] Id. at page 12.
[31] MPSC Case No. U-20162 Sebastian Coppola direct testimony at pages 47-49.

took on additional risks that could have been avoided if it had waited for others to implement all components of ADMS before taking on this project.

The Company now faces cost overruns $17.5 million, excluding the Clicksoft cost portion, and seeks to recover those costs from customers. The Company blames Covid-19 for a portion of the time delay and cost overruns but could not provide an amount as to how much the Covid-19 restrictions may have impacted the time and cost of the project.[32] The Company has also added $6.6 million of project costs for additional reporting features. The necessity and value of those reporting features added after the initial project scope have not been adequately supported and justified.

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

Although a disallowance for imprudence may be premature at this time and until the project is completed and all the costs are known, I recommend that the Commission not approve for inclusion in rate base in this rate case the forecasted capital expenditures of $28,449,000 for the 10 months ending October 2022 and the $12,430,000 for the 12

[32] Exhibit AG-1.9 includes DR AGDE-7.21b.

months ending October 2023.[33] By removing these forecasted costs for the DMS/OMS project, the Commission will preserve its options if after review of the completed project a permanent cost disallowance is warranted.

As stated earlier, if the Commission adopts my proposal to limit strategic capital programs spending to the 20% annual growth rate for 2022 and 2023, no additional disallowances may be necessary for OMS/DMS for the 10 months ending October 2022 and 12 months ending October 2023 due to the more limited capital spending program.

In any case, the Commission should also direct the Company that in its next rate case it should provide a full accounting of the OMS/DMS project costs with sufficient detail for Staff and intervenors to perform a through prudency review of the actual expenditures against the initial project costs, as approved by the Commission in Case No. U-20162.

ESOC – Beginning on page 31 of her direct testimony, Ms. Elliot Andahazy discusses the Electric System Operations Center (ESOC) and also the Alternate System Operations Center (ASOC) which functions as a backup facility to ESOC. In her testimony, Ms. Elliot Andahazy states that the ESOC project began in 2017 and was originally planned to be completed by December 2019 with the ASOC project completed a year later in December 2020.

[33] Exhibit A-12, Schedule B5.4 page 11, line 2. The 10 months ending October 2022 amount is the difference between column (f) and (c).

In response to discovery, the Company reported that the ESOC was completed in August 2021, which is approximately one and one-half years past the original date, and the ASOC is planned to be completed in the first quarter of 2024, or more three years from the original date.[34] Both projects have encountered significant cost overruns. The combined projects had been estimated to cost $110,683,000 in Case No. U-20162 and U-20561. The current forecast by the Company is $133,044,000 for a cost increase of $22,361,000, or more than 20% over the original estimate.[35]

The Company attributes the cost increases to changes in the scope of the projects made after the initial design and delays to project schedules due to the design scope changes, work permit issues, and Covid-19 restrictions.[36]

Q. WHAT IS YOUR ASSESSMENT OF THE ESOC AND ASOC PROJECTS?

A. The problems with the delays and cost overruns for the ESOC and ASOC projects are of the Company's own making. After proposing the projects in both Case Nos. U-20162 and U-20561, and receiving capital funding approval, the Company decided to significantly change the scope of the ESOC project by increasing the square footage of the building by 50% from 42,000 square feet to 63,900 square feet. In her testimony, Ms. Elliott Andahazy states that the Company continued to evaluate the project and information gathered from other utilities after submitting its proposals in the prior rate cases. This information shows

[34] Exhibit AG-1.10 includes DR STDE-4.37 and AGDE-7.218.
[35] Morgan Elliott Andahazy direct testimony at page 37, Table 6.
[36] Id.

the Company made a proposal for funding to the Commission that was still incomplete and premature.[37]

The Company also decided to locate other personnel in the ESOC and incorporate a stand-alone data processing center within ESOC. The Company claims that both of these additions will increase efficiency and collaboration to better serve customers. No specific benefits were presented to support those claims. In response to discovery, the Company provided a comparison of the original cost of $78 million for the ESOC to the final cost of $98.5 million with the major portions of the cost increase of $20.5 million identified. Exhibit AG-1.10 includes this information provided in response to DR AGDE-7.215c.

The schedule provided in response to AGDE-7.215c shows $1.4 million in additional costs for an engineer onsite to oversee and support construction activities; $11.1 million for additional construction costs for the added space, additional permitting costs, and control room equipment; $3.7 million for additional IT equipment for the stand-alone data center; and $4.3 million for additional overheads and AFUDC pertaining to the project cost increase.

The Company has not justified why a scope change was necessary and what tangible benefits will be realized from the added size of the facility, the relocation of additional personnel, and the inclusion of a stand-alone data center. As to the requirement of having a data center within ESOC, the Company stated in response to discovery that ASOC, as a

[37] Id. at page 38.

backup center, will not have its own data center and will operate connected to the Company's main data centers.[38]

Although the final date of completion of the ESOC project may have been delayed a few months by the breakout of the Covid-19 pandemic in the first quarter of 2020, the Company had initially planned to complete the project by December 2019. Therefore, if the Company had held to its original scope and timeline, Covid would not have been an issue. In any case, the Company only attributes $922,500 to the impact of Covid-19 out of a total cost overrun of $20.5 million.[39]

Additionally, due to the work flexibility offered to employees due to Covid-19, approximately half of the operational engineers and SCADA support staff are not making regular use of the space in the ESOC built for them and will work remotely. This development partially negates the need for the large square foot expansion of the building.[40]

In summary, the Company has not adequately justified the expanded scope of the project or made a compelling and convincing case that the additional capital expenditures for the ESOC were justified. Therefore, I propose that the Commission disallow recovery of the $20.5 million as an imprudently incurred cost and this amount be permanently removed from rate base.

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[38] DR AGDE-7.217.
[39] Exhibit AG-1.10 includes DR AGDE-7.214a.
[40] Id. includes DR ST-4.38.

6. Tree Trimming Capital Programs

Q. PLEASE PROVIDE THE CAPITAL EXPENDITURE REDUCTIONS THAT WILL OCCUR FROM THE TREE TRIMMING SURGE PROGRAM.

A. In Exhibit A-22, the Company has outlined the O&M expense and capital expenditures reductions that will ensue as a result of the surge program in coming years. In response to discovery request AGDE-8.261, the Company reaffirmed those savings as they pertain to 2022 and 2023.[41] The O&M portion of these savings will be addressed in the Operation and Maintenance section of my testimony.

With regard to the capital expenditures portion, the table in AGDE-8.261 (Exhibit AG-1.11) shows that between 2022 and 2023 capital expenditures will decrease by $10.9 million due to the positive impact of the tree trimming surge on other programs of the Company, resulting in fewer power outages caused by trees. The amount that can be attributed to the projected test year is $9.08 million ($10.9 x 10/12). I recommend that the Commission remove this amount from the capital expenditures projected by the Company for the 12 months ending October 2023.

7. Customer Benefits of Planned Distribution Investments

Q. DO YOU AGREE WITH THE COMPANY'S PROJECTIONS THAT WITH IMPLEMENTATION OF THE PROPOSED DISTRIBUTION SYSTEM

[41] Exhibit AG-1.11 includes DR AGDE-8.261.

SPENDING PROGRAMS, CUSTOMERS WILL REALIZE ECONOMIC VALUE OF BETWEEN $9.8 BILLION AND $13.2 BILLION?

A. No. Beginning on page 58 of her direct testimony, Ms. Pfeuffer states that the capital expenditures programs proposed by the Company will directly benefit customers by mitigating the impact of severe weather on the electric distribution system. Based on its goal to reach second quartile performance in the reliability indices (SAIDI, SAIFI, and CAIDI)[42] by 2025, the Company projected that it will create economic value of $9.8 billion and $13.2 billion using the Interruption Cost Estimation (ICE) tool developed by Berkley Laboratories. There are several problems with that conclusion and how the amounts were developed.

First, the $9.8 billion and $13.2 billion do not represent solely the projected cost savings from the baseline level of 2020 through 2025. Most of the projected savings are from assuming that the reliability level in 2025 will continue in perpetuity. Without extending the cost savings to perpetuity, the projected cost savings are $2.1 billion and $2.8 billion.

Second, if we were to trust the ICE model, the Company currently is causing economic destruction each year of $1.7 billion based on its baseline levels of SAIDI of 434 minutes, SAIFI of 1.337 outage incidents per customer, and CAIDI of 325 minutes.[43] Using the same approach taken by the Company to calculate the $9.8 billion and $13.2 billion, the

[42] SAIDI = System Average Interruption Duration Index; SAIFI = System Average Interruption Frequency Index; CAIDI = Customer Average Interruption Duration Index.
[43] Figure 1 on page 3 of Exhibit A-23, Schedule M8.

Company would cause economic losses of $25.2 billion to residential, commercial, and industrial customer over the next five years and in perpetuity if the reliability indices were not to improve. I am quite certain that the Company would not agree that it is causing this level of economic loss to its customers annually or in perpetuity. In fact, in discovery, the Company was asked to provide this same information and declined to provide it.[44] It is easy to see from this analysis how preposterous it is to rely on a simplistic model such as ICE to calculate customer benefits for improvements in reliability measures.

Third, in discovery, the Company was asked to provide the working model in Excel with formulas intact and all assumptions in order to validate the calculations and the conclusions from the ICE model. In response, the Company could only provide an abbreviated model without the underlying calculations and factors of costs assigned to the power outage minutes for each customer class. Therefore, the results of the model could not be calculated. Repeated requests for more information could not be satisfied because the Company apparently did not have full access to the detailed model. In fact, in response a discovery request, the Company admitted that it had not validated the accuracy of the model results shown in Ms. Pfeuffer's testimony and exhibit A-23, Schedule M8, page 2.[45]

Fourth, Berkley Laboratories publishes the following warnings with the ICE model: (1) the information is dated with some of the costs of interruptions being dated and older than 20 years, (2) the information is not statistically representative for all regions of the U.S.,

[44] DR AGDE-6.181b.
[45] DR AGDE-6.196.

and (3) the model is not appropriate for estimating costs of widespread, long-duration interruptions. In other words, Berkley Labs warns users to not trust the model results at face value.

Fifth, the model includes the Company's goals to lower the three main reliability indices. The Company plans to lower the SAIDI-All Weather results from the 2020 baseline level of 434 minutes to 199 minutes by the end of 2025. This 46% improvement over a five-year period seems rather aggressive and ambitious. Similarly, the Company has projected improvements in the average time of customer interruptions (CAIDI) from 325 minutes to 201 minutes in 2025 for a 38% reduction. The SAIFI time also would improve by 26%, from 1.337 average outage incidents per customers to 0.992, or less than one incident per customer. These goals are so ambitious to border on the unrealistic. In discovery the Company was asked to state how it would be held accountable if it made the necessary capital investments and the expected electric system reliability measures discussed above were not achieve in 2025. The Company reiterated its expectation to reach the reliability goals and refused to state how it would be held accountable.[46]

In summary, the Company's testimony that it could achieve customer benefits of $8.9 billion to $13.2 billion is unreliable and misleading. The ICE has significant faults and shortcomings, and appears to greatly overstate the economic losses suffered by customers

[46] Exhibit AG-1.12 includes DR AGDE-6.181d.

during power outages. The Commission should not rely on this information or give it any weight in its deliberations about the Company's spending programs.

C. Power Generation Plant

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

A. On page 1 of Exhibit A-12, Schedule B5.1, the Company forecasted both Routine and Non-Routine capital expenditures in the Power Generation area of $489.6 million for 2021, $398.6 million for the 10 months ending October 2022, and $427.0 million for the 12 months ending October 2023. In my review of the proposed expenditures, I have identified several adjustments which I discuss below.

1. Power Generation Projects Lacking Full Authorization

Q. PLEASE DISCUSS THE FIRST GROUPING OF ADJUSTMENTS THAT YOU PROPOSE FOR 2022 AND 2023.

A. In response to discovery, the Company reported that several power generation projects had not yet received full authorization for the proposed capital spending included in this rate case for 2022 and 2023. The response to DR STDE-3.7c identifies 14 projects where authorization for the proposed spending level would not be received until later in 2022 and in some case not until 2023.[47]

Projects that lack the requisite internal approval to proceed with the proposed capital spending amount should not be included in rate base in this rate case. These projects are still undergoing internal review and the fact that they have not been approved indicates that the timing and amount of the proposed spending could change as management decides to re-prioritize projects. It is not appropriate to include the cost of the projects in rate base and for the Company to begin to recover depreciation expense and a return on investment before those projects have been fully authorized.

Q. HAVE YOU DETERMINED THE AMOUNT OF CAPITAL EXPENDITURES THAT SHOULD BE REMOVED FROM RATE BASE FOR THE APPLICABLE PROJECTS?

A. Yes. In Exhibit AG-1.14, I listed 13 projects and the related amount included in the Company's exhibits for the projected periods.[48] The total amount is $54,575,000 for the 10 months ending October 2022 and $112,009,000 for the 12 months ending October 2023.

I recommend that the Commission remove those amounts from the Company's proposed capital expenditures for the applicable forecasted periods.

[47] Exhibit AG-1.13 includes DR STDE-3.7c.
[48] The 14th project is the Slocum Battery Pilot, which will be discussed separately later in my testimony.

2. Hydrogen Facility Pilot Project

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED HYDROGEN PILOT PROJECT.

A. Beginning on page 32 of his direct testimony, Mr. Justin Morren discusses the hydrogen fuel system project that the Company proposes to undertake. The Company proposes to build an 11 MW electrolyzer plant adjacent to the Blue Water Energy Center (BWEC). The premise for the project is that the hydrogen plant would utilize excess renewable power during periods of low energy demand to generate hydrogen fuel, which would be used later as a fuel source to supplement natural gas used in the generation of electricity at BWEC. The proposed cost of the pilot project is $44.6 million, of which $19.6 million is included in this rate case and the remainder to be spent after the end of the projected test year.[49]

In his testimony, Mr. Morren touts the hydrogen project as a step toward the Company's goal to achieve net zero carbon emissions by 2050, with the reasoning being that the hydrogen fuel would reduce the use of natural gas in the generation of electricity at BWEC. Mr. Morren also points to the use of intermittent renewable energy during periods of low energy demand. He also states that hydrogen fuel has a promising future in Michigan with

[49] Justin Morren direct testimony at page 39.

targets to reduce the cost of generating hydrogen but does not provide any supporting details.

To support his case, Mr. Morren identifies a handful of other utilities in the country that have been experimenting with generating hydrogen from renewable energy. However, no data was provided on the cost and on the success or failure of those hydrogen plants in order to establish a baseline of learnings about what other utilities have experienced. Mr. Morren insists that this is an opportune time to undertake the hydrogen project because of the sentiment around the industry and government that carbon reduction is necessary.

Among the learnings that it seeks to gather from the pilot project, Mr. Morren has identified the following: (1) scalability of the plant equipment, such as cooling, fuel blending, hydrogen burn characteristics, and emissions from the gas turbine; (2) the effect on the equipment from daily shutdowns and restarts; (3) seasonal weather impact on operation and capability of the plant to produce hydrogen.

The project timeline starts with engineering and permitting in 2022, followed with procurement of certain long-lead time equipment by the end of 2022, start of construction in early 2023, and commencement of operation in the fall of 2024. Following the first two years of operation, the Company envisions potential scaling up of operations and expansion into other hydrogen facilities.

Q. HAS THE COMMISSION PROVIDED ANY GUIDANCE ON THE STRUCTURE AND APPROACH TO BE TAKEN BY UTILITIES PROPOSING PILOT PROJECTS?

A. Yes. In its order of February 4, 2021 in Case No. U-20645, the Commission updated its guidance on the structure and approach to be taken by utilities proposing pilot projects, and identified six major objective criteria. A copy of the Commission order with the six criteria has been included in Exhibit AG-1.15. Below, I will identify certain key aspects within the criteria.

1. **Pilot need and goals detailed.**
   a. Need for the pilot is expressed. Results of past similar pilots and findings are shared to justify the need for the proposed pilot.
2. **Pilot design and evaluation plan designed and presented together**.
   a. Pilot program design and evaluation plans are designed together so examined metrics and collected data support evaluation of the pilot in meeting goals and desired learnings
   b. If applicable, define target customer population, selection criteria…and recruitment plans for customer adoption and satisfaction.
3. **Pilot project costs detailed**.
   a. Project costs are detailed…
   b. Availability of non-utility funding…
   c. Anticipated cost-effectiveness and net benefits when deployed at scale… Quantification of expected benefits of the pilot and the evaluation and criteria/methods used.

On page 10 of the order, the Commission also stated that "The Commission recognizes that, <u>even though a pilot program may not be initially cost-effective, consideration must be given to whether the pilot program will grow into a cost-effective program when deployed at full scale</u>. Moreover, quantification of expected benefits is essential for the

Commission to consider in reviewing pilot program proposals through the ratemaking process." [Emphasis added]

Q. WHAT IS YOUR ASSESSMENT OF THE PROPOSED HYDROGEN PLANT PILOT PROJECT?

A. At nearly $45 million, assuming no cost overruns, the hydrogen plant pilot project is too costly an investment without first determining the economic viability of hydrogen plants once deployed at full scale. The Company's pilot proposal falls short of the Commission's guidance on proposed pilot projects and also fails to make a convincing case it can create sufficient value for customers relative to the investment required. I will discuss some of these shortcomings below.

First, the Company has not provided any analysis or evidence that hydrogen plants can generate hydrogen at a reasonable cost once fully scaled to commercial facilities. This is a key threshold question that must be answered. It makes little sense to spend $45 million on a pilot project to learn how to incorporate the proposed facility within the BWEC and how to refine the facility's operation if ultimately the cost of hydrogen production is uneconomical. In fact, in Exhibit A-12, Schedule B5.1.2, the Company glosses over this key point when matching its proposal to the Commission guidance criteria. Furthermore, in his testimony identifying lessons to be learned from the proposed pilot project, the plant's economic viability is not even mentioned as a key finding from the execution of the pilot project.

Second, the Company was asked in discovery why it does not make more sense to wait and learn from the other hydrogen projects currently underway in other states before spending $45 million on its own hydrogen pilot project. In response, the Company stated that it is important to advance the technology and for the Company to gain specific knowledge.[50] Such a view would make sense if there was a high likelihood that the hydrogen technology would be economically viable once scaled up. However, that important evaluation has not been performed. It is not the role of a utility to be a development test site for experimental technology.

Third, the Company may have done some research on similar hydrogen projects undertaken by a few other utilities around the country but has not provided any evidence of the successes and failures of those projects. The lessons learned by those other utilities would be invaluable in either designing the pilot project or avoiding it entirely if the results from the other utility projects show a lack of economic viability. There is not much value in being an early adaptor of new technology if one can learn from others and avoid costly mistakes and large risky investments, particularly when $45 million in spending is involved.

Fourth, the volume of fuel produced from the proposed hydrogen facility and the CO2 emissions avoided are miniscule in comparison to the operation of BWEC. In response to discovery, the Company stated that the facility would displace 31,776 MMBtu of natural

[50] DR AGDE-3.97a.

gas and avoid 1,861 tons of CO2 emissions annually.[51] In comparison, BWEC is expected to burn 56,196,000 MMBtu[52] in 2023 and emit 3.3 million tons of CO2. The 11 MW proposed hydrogen facility represents 0.0565% of the fuel usage and of the CO2 emissions from the BWEC. As is readily apparent, the facility will hardly make a difference in the operation of BWEC but would come at a capital cost of $45 million plus operating expenses.

Fifth, the Company has assumed that the hydrogen plant will operate at an average capacity factor of 18%,[53] which means that more than 80% of the time it will sit idle and not operate.

Sixth, on page 39 of his direct testimony, Mr. Morren has identified $120,000 of O&M expense and $350,000 in power supply costs for the hydrogen plant to operate and generate sufficient hydrogen to displace 31,776 MMBtu of natural gas. The total operating costs of $470,000 translate to a cost of $14.79 per MMBtu ($470,000 ÷ 31,776 MMBtu). The Company expects to purchase natural gas in 2023 for BWEC at $3.40 per MMBtu.[54] The hydrogen facility would produce hydrogen at a cost of more than four times the cost of natural gas. Therefore, the hydrogen facility would increase overall power costs for the Company and on this test alone fails the economic viability test.

Seventh, the Company has not performed a long-term cost/benefit analysis of either the pilot project or the long-term economic viability of larger hydrogen plants. In response to

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[51] Exhibit AG-1.16 included DR AGDE-3.96a and b.
[52] DTEE Ryan Pratt direct testimony on page 11 in Case No. U-21050.
[53] Exhibit AG-16, DR AGDE-3.96a.
[54] DTEE Ryan Pratt direct testimony on page 11 in Case No. U-21050.

discovery, the Company stated that "The goal of the project is to gain information and experiences that can be brought to bear in the quest to support CO2 reductions goals and advance the possibilities of hydrogen usage in utility generation options…hydrogen is projected to decrease in cost when deployed at full scale and across the industry…."[55] It is clear from the response that the Company has not made any long-term economic viability evaluations of hydrogen facilities for either the pilot project or any potential larger facilities down the road when the cost of hydrogen production supposedly may decrease.

In summary, it appears that the main driver for building the hydrogen facilities is for the Company to gain some accolades that it is moving towards its goal of being carbon neutral by 2050. Although carbon reduction may be a worthy goal, it should not be done solely on the backs of the Company's customers. The Commission guidance criteria on pilot projects encourages utilities to search for non-utility funding of pilot projects. In this case, the Company's shareholders could contribute a portion of the project's required capital. Given that the hydrogen facility could enhance the Company's image as a responsible utility that wishes to reduce carbon emissions toward its well-publicized goal of being carbon neutral by 2050, a significant capital contribution by Company shareholders would seem eminently reasonable.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE PROPOSED HYDROGEN PLANT PILOT PROJECT?

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[55] DR AGDE-3.95 and AGDE-3.97c.

A. The Company has not made a compelling and convincing case that the proposed hydrogen pilot project is in the best interest of its customers. The facility is extremely costly relative to the learnings that the Company seeks to gather from the pilot project. Furthermore, there is no evidence that the pilot project would lead to the conclusion that a larger scale facility would be economically viable. To the contrary, the early evidence from operation of the pilot facility indicates that the cost of generating hydrogen fuel to displace natural gas would be more than four times the cost of natural as a fuel for power generation.

Therefore, I recommend that the Commission reject the Company's proposed hydrogen pilot project and remove $756,000 of capital expenditures from 2020/2021, $882,000 for the 10 months ending October 2022, and $17,401,000 from the 12 months ending October 2023.

3. Slocum Battery Energy Storage System (BESS) Pilot

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED SLOCUM BESS PILOT PROJECT.

A. Beginning on page 40 of his direct testimony, Mr. Justin Morren discusses the Slocum BESS pilot project that the Company proposes to undertake. The Company proposes to install a 14 MW battery energy storage system in the City of Trenton to replace a diesel-powered peaker generating unit. According to the Company, the Slocum BESS unit will be capable of delivering up to 56 MWh of energy for a period of 4 hours. The proposed cost of the pilot project is $33.7 million and that cost is included in this rate case primarily between 2022 and the end of the projected test year.[56]

In his testimony, Mr. Morren states that the Slocum BESS will store excess energy generated during off-peak hours and be available for dispatch during higher-priced peak hours. Mr. Morren also touts the Slocum BESS pilot project as another step toward the Company's goal to achieve net zero carbon emissions by 2050 with the reasoning being that the stored energy would reduce the use of the current diesel generation. Mr. Morren also points to the use of intermittent renewable energy during periods of low energy demand, although he makes no direct link that the Slocum BESS unit would store renewable energy.

To support his case, in Exhibit A-12, Schedule B5.1.3, Mr. Morren reports that in the past few years, other utilities have brought utility-scale BESS units into operation and points to Indianapolis Power & Light who pioneered a 20 MW lithium-ion battery, known as the Harding Street Energy Storage System. However, no data was provided on the cost and on the success or failure of those BESS units in order to establish a baseline of learnings about what other utilities have experienced.

Among the learnings that the Company seeks to gather from the pilot project, Mr. Morren has identified the following: (1) Gain experience with the battery supply chain and installation process replacing a fossil-fueled peaker; (2) assess the dispatch (hourly, daily,

[56] Justin Morren direct testimony at page 43.

and seasonal profile) of the BESS in the MISO wholesale energy market; (3) assess the ability for the BESS to support energy supply flexibility in the MISO ancillary services market; (4) evaluate the annual cost of BESS operation and maintenance; and (5) evaluate the annual PSCR value of operating the BESS in the MISO energy, capacity, and ancillary services markets.

The timeline of the pilot project starts with battery procurement in the early part of 2022, followed by site preparation in 2022, and commencement of operation in June 2023. In his testimony, Mr. Morren states that a successful pilot, coupled with expected future cost favorability, will advance the role of battery storage in the transformation of the Company's electric generation fleet. However, no specific or quantified benchmarks were outlined as to what will be considered a successful pilot or what the cost favorability measures are that will be used to expand the role of battery storage past the pilot project.

Q. DO THE COMMISSION GUIDANCE CRITERIA FOR PILOT PROJECTS APPLY ALSO TO THE SLOCUM BESS PILOT PROJECT?

A. Yes. The Commission pilot project guideline criteria that I discussed above and are outlined in Exhibit AG-1.15 also apply to the Slocum BESS pilot project.

Q. WHAT IS YOUR ASSESSMENT OF THE PROPOSED SLOCUM BESS PILOT PROJECT?

A. The Slocum BESS pilot project suffers from the same problems and shortcomings as the hydrogen pilot project discussed above. At nearly $34 million, the Slocum BESS pilot project is too costly an investment without first determining the economic viability of BESS units once deployed at full scale. The Company's pilot proposal falls short of the Commission's guidance on proposed pilot projects and also fails to make a convincing case it can create sufficient value for customers relative to the investment required. I will discuss some of these shortcomings below.

First, the Company has not provided any analysis or evidence that the Slocum BESS unit can provide power capacity at a reasonable cost for the pilot itself or once fully scaled to a larger size for commercial operation. This is a key threshold question that must be answered. It makes little sense to spend $34 million on a pilot project to learn how to incorporate the storage system and how to refine the facility's operation if ultimately the cost of the storage system is uneconomical. In Exhibit A-12, Schedule B5.1.3, the Company glosses over this key point when matching its proposal to the Commission guidance criteria. Furthermore, in his testimony identifying lessons to be learned from the proposed pilot project, the Slocum BESS unit economic viability is not even mentioned as a key finding from execution of the pilot project.

Second, in response to discovery, the Company admitted that at $33.7 million, the cost of capacity for the Slocum BESS unit is $2.4 million per MW in comparison to the cost of

CONE for new capacity in MISO Zone 7 of $94,000 per MW.[57] This disparity is enormous and by a factor of 25 times compared to what the Company can build or buy capacity to replace the diesel peaker unit. Furthermore, the BESS unit only provides up to 4 hours of energy capacity, meaning that if peak demand continues past 4 hours during hot summer days, the Company will need to rely on other generating units or buy power in the MISO market. In other words, the BESS unit is a temporary energy capacity replacement and not a longer duration source of energy for extended periods of peak power demand which could be provided by traditional natural gas-fueled peaker generating units.

Third, the Company was asked in discovery why it does not make more sense to wait and learn from other BESS projects currently underway in Michigan and other states before spending $34 million on its own BESS pilot project. In response the Company stated that it is important for the Company to gain experience and establish a process for future grid-scale battery project development, battery suppliers, and battery installation, among other reasons.[58] Those objectives would make sense if there was a high likelihood that the BESS units would be economically viable once scaled up. However, that important evaluation has not been performed. Instead, the Company seems to be proceeding on the assumption that installation of BESS units is a foregone conclusion and only needs to gain experience as to how to incorporate them within its operations.

[57] Exhibit AG-1.17 includes DR AGDE-3.103a
[58] DR AGDE-3.104a.

Fourth, the Company may have done some research on similar BESS projects undertaken by a few other utilities around the country but has not provided any evidence of the successes and failures of those projects. The lessons learned by those other utilities would be invaluable to either properly designing the proposed pilot project or avoiding it entirely if the results from those other utility projects show a lack of economic viability. As stated earlier, there is not much value in being an early adaptor of new technology if one can learn from others and avoid costly investments, particularly when $34 million in spending is involved. The list of desired learnings identified by the Company could easily be garnered from BESS projects underway at other utilities without incurring $34 million to repeat the same processes.

Fifth, in response to DR STDE-3.7c (Exhibit AG-1.13), the Company reported that the Slocum Battery Pilot project costs had not yet received full authorization and such authorization was not expected until the spring of 2022. As stated earlier with regard to other projects that had not received full authorization prior to the filing of the Company's testimony in this rate case, it is premature to include project costs in rate base that have not been fully vetted and approved. Therefore, simply on this basis alone, the project costs should be removed from inclusion in this rate case.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE PROPOSED SLOCUM PILOT PROJECT?

A. The Company has not made a compelling and convincing case that the proposed Slocum BESS pilot project is in the best interest of its customers. The facility is extremely costly relative to the learnings that the Company seeks to gather from the pilot project. Furthermore, there is no evidence that the pilot project would lead to the conclusion that larger scale installation of BESS units would be economically viable. To the contrary, the evidence from the cost of the Slocum project shows that the cost of BESS units is still prohibitively expensive and not economically viable. Customers would be best served if the Company suspended the pilot project and waited until the cost of BESS units declines sufficiently to make testing and installation of such units economically viable.

Therefore, I recommend that the Commission reject the Company's proposed hydrogen pilot project and remove $45,000 of capital expenditures from 2021, $7,188,000 for the 10 months ending October 2022, and $26,430,000 from the 12 months ending October 2023.

4. Blackstart Infrastructure Improvements

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES FOR ASSET IMPROVEMENTS TO PROVIDE BLACKSTART SERVICES.

A. On pages 31 and 32 of his direct testimony, Mr. Morren briefly states that line 29 of page 2 of Exhibit A-12, Schedule B5.1, includes capital expenditures for three projects: Blackstart Infrastructure, Site Security, and NERC Compliance. The extent of the explanation about the $47.8 million of proposed capital expenditures for the three projects is a couple of sentences with no particular insight offered about the Blackstart infrastructure improvements.

In discovery, the Company was asked to provide a breakdown of the costs and explain what was being done with regard to Blackstart service that required additional capital expenditures. In response, the Company provided cost details over the 2021 to 2023 time period but no further explanation about the proposed improvements. Additionally, the Company could not provide a timeline for filing revised rates with FERC to recover costs related to the new investments made to Blackstart assets used to provide Blackstart services to the power grid.

The confidential Attachment to DR AGDE-3.94a shows that capital expenditures on Blackstart infrastructure were forecasted at $3,860,000 for 2021, $32,354,000 for the 10 months ending October 2022, and $11,353,000 for the 12 months ending October 2023.[59]

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION?

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

[59] Exhibit AG-1.18 CONF includes DR AGDE-3.94a with Confidential attachment.

Therefore, I recommend that the Commission remove $3,860,000 of capital expenditures for 2021, $32,354,000 for the 10 months ending October 2022, and $11,353,000 for the 12n months ending October 2023 from the Company's proposed capital expenditures in this rate case.

<u>5. BWEC Covid-Related Costs</u>

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO INCLUDE COVID-19 RELATED COSTS IN THE CAPITAL EXPENDITURES FOR THE CONSTRUCTION OF BWEC.

A. On pages 30 of his direct testimony, Mr. Morren briefly discusses the use of previously reserved contingency costs for the construction of BWEC. Included in the explanation is an amount of $4.3 million that the Company attributes to incremental costs associated with a six-week suspension of the project due to the Covid-19 pandemic. In his testimony, Mr. Morren does not provide any insight as to the composition of these costs and how they occurred. In discovery, the Company was asked to provide the specific incremental costs for each of the items incurred that make up the $4.3 million. In the response, the Company repeated the same short explanation provided in Mr. Morren's testimony with no detailed accounting of the costs incurred. In a separate response to a discovery question posed by Staff, the Company stated that the $4.3 million was booked in June 2020 with no further elaboration on the composition or origin of the costs incurred. Exhibit AG-1.19 includes DR AGDE-3.92b and STDE-2.9b.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION?

A. The Company has not provided sufficient information to adequately justify the inclusion of $4.3 million of capital expenditures to the BWEC construction project related to Covid-19. Without knowing the composition of these costs and how they came about, it is not possible to determine that they are valid and reasonable costs to include as capitalized additions to rate base for the BWEC project. For example, if the Company simply paid employees or contractors to stay home with no productive work done on the project those costs may not be reasonable costs to be capitalized as part of the project costs and should likely have been expensed as incurred. Without sufficient information, it is not possible to make those critical assessments.

Therefore, I recommend that the Commission remove the $4.3 million recorded to rate base in 2020 from the Company's proposed rate base additions in this rate case.

D. Nuclear Production Plant

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S PROJECTED CAPITAL EXPENDITURES FOR NUCLEAR PRODUCTION PLANT ITEMS.

A. On page 1 of Exhibit A-12, Schedule B5.3, the Company forecasted capital expenditures for Nuclear Production Plant, excluding nuclear fuel, of $150.9 million for 2021, $176.7 million for the 10 months ending October 2022, and $94.2 million for the 12 months ending October 2023. In my review of the proposed expenditures, I have identified several adjustments, which I discuss below.

<u>1. Plant Support Facilities & Equipment</u>

Q. PLEASE DISCUSS THE GROUP OF ADJUSTMENTS THAT YOU PROPOSE FOR CAPITAL EXPENDITURES PERTAINING TO SUPPORT FACILITIES AND EQUIPMENT AT THE FERMI 2 NUCLEAR PLANT.

A. In Exhibit A-12, Schedule B5.3, the Company identifies several individual projects and proposed capital expenditures for the period from 2020 through October 2023. In reviewing several of the proposed projects I identified three projects that warrant removal from the total amount of capital expenditures proposed by the Company. They are the Plant Wireless project, the Security System Computer project, and the Plant Radio System. In each of these cases, the Company failed to provide adequate information to support the reasonableness of the proposed capital expenditures.

<u>Plant Wireless Project</u> - With regard to the Plant Wireless project, the Company has proposed to spend $2,949,000 in the 10 months ending October 2022 and $3,186,000 for the 12 months ending October 2023, for a total amount of $6.1 million to be included in this rate case. In his direct testimony, Mr. Jeffrey Davis included no explanation for this large planned expenditure. The information filed by the Company as Part III information provides monthly budget cost projections but no further information as to what this project entails, the necessity to undertake the project at this time and why it is necessary, how the projected costs were determined, or why they are reasonable.

In discovery, the Company was asked to explain what was being done with the plant wireless system that would require $6.1 million in capital expenditures and to provide evidence that the projected cost was not excessive. In response, the Company referenced Attachment 9 of the Part III information for additional information and listed five items of precautions that equipment installers need to consider when working in the nuclear facility.[60] Neither of the responses address the request made. As discussed earlier, the Part III information is devoid of any explanations or justification about the project other than monthly cost projections. With regard to the challenges of working within a nuclear facility, those challenges in and of themselves do not provide evidence to spend $6.1 million on this project.

The Company has failed to provide any support of a premium amount to be paid above some base level of costs or any competitive project bid information that shows the projected costs are reasonable and should be included in rate base in this rate case. Therefore, I recommend that the Commission remove the forecasted capital expenditures $2,949,000 for the 10 months ending October 2022 and $3,186,000 for the 12 months ending October 2023.

[60] Exhibit AG-1.20 includes DR AGDE-7.226d.

Security Video System – For the Security Video System, the Company has proposed to spend $2,047,000 in 2021, $10,618,000 for the 10 months ending October 2022, and $12,073,000 for the 12 months ending October 2023 for a total amount of $24.7 million to be included in this rate case. In his direct testimony, Mr. Jeffrey Davis dedicated 10 lines to identify the major components of the system and stated that periodic replacement is necessary due to the age of the system approaching 20 years.

In discovery, the Company was asked to explain why replacement of the security video system would require $24.8 million in capital expenditures and to provide evidence that the projected cost was not excessive. In response, the Company referenced Attachment 9.3 of Part III information and listed five items of precautions that equipment installers need to consider when working in the nuclear facility.[61] In this case again, neither of the responses addressed the request made. As discussed earlier, the Part III information is devoid of any explanations or justification about the project other than monthly cost projections. With regard to the challenges of working within a nuclear facility, those challenges in and of themselves do not provide evidence to spend $24.7 million on this project.

The Company has failed to provide any support of a premium to be paid above some base level of costs or any competitive project bid information that shows the projected costs are reasonable and should be included in rate base in this rate case. Therefore, I recommend

[61] Exhibit AG-1.20 includes DR AGDE-7.219a-c.

that the Commission remove the forecasted capital expenditures of $2,047,000 for 2021, $10,618,000 for the 10 months ending October 2022 and $12,073,000 for the 12 months ending October 2023.

__Plant Radio System__ - For the Plant Radio system, the Company has proposed to spend $391,000 in 2020, $2,187,000 in 2021, $1,041,000 in the 10 months ending October 2022, and $3,977,000 for the 12 months ending October 2023 for a total amount of $7.1 million to be included in this rate case and an additional $1.5 million past October 2023. In his direct testimony, Mr. Jeffrey Davis included no explanation for this large planned expenditure. The information filed by the Company as Part III information provides monthly budget cost projections but no further information on what this project entails, the necessity to undertake the project at this time and why it is necessary, how the projected costs were determined, or why they are reasonable.

The Company has failed to provide sufficient information to justify this large amount of capital expenditures. Therefore, I recommend that the Commission remove the capital expenditures of $391,000 for 2020, $2,187,000 for 2021, $1,041,000 for the 10 months ending October 2022, and $3,977,000 for the 12 months ending October 2023.

In total, for the three projects, I recommend that the Commission remove the following capital expenditures in the calculation of rate base in this rate case: $391,000 for 2020, $4,234,000 for 2021, $14,608,000 for the 10 months ending October 2022, and $19,236,000 for the 12 months ending October 2023.

E. Customer Service Projects

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S PROJECTED CAPITAL EXPENDITURES FOR CUSTOMER SERVICE PROJECTS.

A. On page 1 of Exhibit A-12, Schedule B7.3, the Company forecasted capital expenditures for Customer Service projects of $39.7 million for 2021, $57.9 million for the 10 months ending October 2022, and $56.4 million for the 12 months ending October 2023. In my review of the proposed expenditures, I have identified several adjustments which I discuss below.

1. Advanced Customer Pricing and Time of Use Pilots

Q. PLEASE DISCUSS THE ADVANCED CUSTOMER PRICING AND TIME OF USE PILOTS THAT ARE UNDERWAY AND THE RELATED CAPITAL EXPENDITURES INCURRED TO DATE AND PROJECTED IN THE FUTURE.

A. Both Company witnesses Angie Pizzuti and Neal Foley discuss the Advanced Customer Pricing Pilot (ACPP) and the Time of Use (TOU) pilot in their respective testimony. Mr. Foley addresses the results of the combined ACPP and TOU pilot and the rate design aspects. Ms. Pizzuti primarily address the capital expenditures and O&M expenses of the pilot, including the deferral of O&M costs.

Line 1 of Exhibit A-12, Schedule B7.3, shows that the Company incurred capital expenditures of $8,241,000 in 2020 for the ACPP/TOU pilot with additional amounts forecasted of $2,122,000 in 2021, $18,932,000 for the 10 months ending in October 2022. And $11,175,000 for the 12 months ending October 2023. In Exhibit A-13, Schedule C5.9.2, the Company shows that between 2019 and 2022 it plans to defer $7,300,000 of O&M expenses in a regulatory asset for future recovery and incur additional O&M expenses of $17,100,000 in 2022 and 2023, which it also plans to defer in the regulatory asset.

Given the large amounts proposed in the two exhibits, in discovery the Company was asked to provide the total capital and O&M expenditures expected to be incurred for the ACPP and TOU pilot from inception to completion. In response, the Company provided a schedule that shows $49.1 million of capital expenditures to be incurred from 2019 to 2023 plus an additional $24.4 million of O&M expenses, either deferred or expensed over the same time period.[62] The total amount of capital expenditures and O&M costs for this pilot over the five-year period is $73.5 million.

The schedule provided by the Company in response to DR AGDE-8.273a shows that as of the end of 2021 the Company spent $17.3 million in capital expenditures and $6.1 million in deferred O&M costs for a total amount of $23.4 million. Therefore, an additional $50 million remains to be spent in 2022 and 2023.

[62] Exhibit AG-1.21 includes DR AGDE-8.273a.

Q. WHAT IS YOUR ASSESSMENT OF THE PROPOSED $73.5 MILLION IN COSTS TO COMPLETE THE ACPP/TOU PILOT?

A. The $73.5 million is an extraordinary amount that I do not believe the Commission or other parties to this rate case, or prior rate cases, envisioned when the idea of the ACPP and TOU pilot first arose and later morphed. Although the genesis of the ACPP/TOU pilot goes back to Case No. U-18255, the Company proposed a pilot program with multiple new rates in Case No. U-20602. However, in that same case, the Commission narrowed the scope of the TOU pilot to only two rate schedules from the Company's proposed six rate schedules.

At the Commission's request on October 3, 2019, the Company filed an updated application and affidavit by Camilo Serna with a Revised Attachment A-2 showing that the cost of the Advanced Customer Pricing Pilot would be approximately $7.3 million based on the Company only pursuing testing of two TOU rate schedules. Mr. Serna also made reference to additional IT costs presented by Company witness Griffin in Case No. U-20561. On page 32 of his direct testimony in that rate case, Mr. Griffin identified $15.9 million of IT capital expenditures for the Time of Use project. However, that capital cost projection was based on the Company implementing 6 new rates for the pilot, 2 Time of Use rates, and 2 Demand rates, and 2 Hybrid rates (TOU and Demand). This project appears to be much more than the pilot program approved by the Commission in its order of February 4, 2021 in Case No. U-20602 when it approved a delay in the implementation of the pilot.

In other words, this rate case is the first time where the Company has presented the full scope of its plans to implement a pilot program for ACPP/TOU that will cost $73.5 million.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. It is evident that the total cost of the ACPP/TOU has mushroomed to an extremely large amount, well above reasonable expectations. The extremely large cost raises questions whether it is still in the best interest of customers to continue to implement the pilot project as proposed by the Company. The best course of action at this point may be for the Company, Staff, and other stakeholders to determine what the least cost option should be going forward to significantly reduce the cost of the ACPP/TOU pilot.

Therefore, I recommend that the Commission temporarily suspend any further work and spending on the pilot program until a lower cost path is agreed to by the parties and approved by the Commission. At this time, the Commission should remove from this rate case all capital expenditures and deferred O&M costs for 2022 and 2023. Specifically, the Commission should remove capital expenditures of $18,932,000 for the 10 months ending October 2022, and $11,175,000 for the 12 months ending October 2023.

2. DTE Pre-Pay Program

Q. PLEASE BRIEFLY DESCRIBE THE DTE PRE-PAY PROGRAM AND THE RELATED CAPITAL EXPENDITURES PROPOSED BY THE COMPANY.

A. Beginning on page 84 of her direct testimony, Ms. Pizzuti presents the DTE Pre-Pay Program as an attractive alternative to customers to gain more control over their energy usage. According to Ms. Pizzuti, customers would be able to purchase electricity in advance by building a credit balance on their account with the Company and replenishing the balance with additional pre-payments as the customer's account is billed for power used during the month. If the customer fails to replenish their account and the balance drops below zero, the customer would be remotely disconnected through the AMI meter from receiving electrical service until unpaid charges are paid and the customer pays enough to achieve a minimum credit balance.

In her testimony, Ms. Pizzuti points to the fact that ahead of this rate case and cost recovery proposal, the Company filed a request with the Commission in Case No. U-21087 to waive compliance with certain MPSC Billing Practice Rules that would otherwise be violated by the prepay program DTE designed, and for "approval" of its prepay program. Ms. Pizzuti theorized that as the program participation scales up customer arrears would decline and uncollectible costs would be reduced. However, no specific participation goals were provided and no uncollectible cost reductions were identified.

Line 52 of Exhibit A-12, Schedule B5.7.3, shows that the Company forecasted capital expenditures for this program of $6,725,000 for 2021, $1,250,000 for the 10 months ending October 2022, and $4,647,000 for the 12 months ending October 2023.

Q. WHAT IS YOUR ASSESSMENT OF THE DTE PRE-PAY PROGRAM PROPOSED BY THE COMPANY?

A. The Company's proposal is a classic case of a solution looking for a problem. The Company has not provided any evidence that customers are seeking the type of service that would be provided by the Pre-Pay Program. From Ms. Pizzuti's testimony, it appears that the target customers are those who have difficulties paying their electric bills and are building arrears on their account. It is difficult to fathom how customers who typically accumulate large arrears because they cannot or will not pay their electric bills after the bill is issued would have sufficient money and would be willing to pre-pay those bills.

In discovery, the Company was asked to provide the number of customers who have asked for a bill pre-pay program. In response, the Company stated that it did not have any data on customers who asked for such a program. The Company also was asked to provide the number of customers it expects would enroll in the proposed pre-pay program and to provide the basis for the forecast. In response, the Company stated that it expected 3,000 customers to enroll the first full year after implementation and to reach 40,000 participants in five years.[63] No basis was provided for these forecasts. A reference to the direct testimony of Company witness Michael Hatsios in Case No. U-21087 provided no additional information on enrollment levels. It is evident that the enrollment levels put forth are unsubstantiated and pure speculation.

[63] Exhibit AG-1.22 includes DR AGDE-8.295a and d.

In discovery, the Company also was asked to provide the expected reduction in uncollectible accounts costs after three years from the start of the program and after the expected maximum level of program participation. In response, the Company could not identify any specific uncollectible cost savings and repeated Ms. Pizzuti's testimony.[64]

The Company was also asked to provide a copy of the cost/benefit analysis that shows the project is economically justified. In response to the discovery request, the Company pointed to its Project Prioritization Score sheet.[65] This document is simply a project summary that describes certain key features and identifies the forecasted costs. It does not include any cost savings or benefits to show any economic justification to undertake this project.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The Company has not presented any of the basic evidence necessary to show that there is sufficient demand from customers for the proposed pre-pay program and that future participation would be at a level to make this project a worthwhile undertaking. Furthermore, although the Company hopes that if enough customers participate it could potentially reduce uncollectible costs, there is no evidence presented that economically justifies the proposed $12.6 million in capital spending.

[64] Id. includes DR AGDE-8.295f.
[65] Id. includes DR AGDE-2.295g.

Therefore, I recommend that the Commission remove $6,725,000 if capital expenditures for 2021, $1,250,000 for the 10 months ending October 2022, and $4,647,000 for the 12 months ending October 2023 from this rate case.

3. Digital Product Teams

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED SPENDING ON DIGITAL SYSTEMS AND DIGITAL CONTENT FOR THE BRIDGE PERIOD AND TEST YEAR.

A. Beginning on page 41 of her direct testimony, Ms. Pizzuti discusses the multitude of projects and activities that the Company has embarked on to provide more digital content to customers through its website and customer mobile phones accessing it website and other systems. The Company has formed Digital Product Teams that constantly develop new digital features and content and disseminate it to customers to increase customer awareness of digital channels. The intent of the Company in developing digital systems and initiatives appears to be to reduce customer calls to its customer service centers and improve customer satisfaction with its services.

However, when asked to provide the tangible benefits and cost savings that would result from the implementation of the various projects, the Company could not provide any such information or provided insufficient information that does not economically justify the large capital expenditures.[66] Often the Company points to its Project Prioritization Score sheet which does not include the requested information.

Q. ARE THERE CERTAIN PROJECTS WITHIN THE DIGITAL PRODUCT TEAM GROUPS FOR WHICH YOU PROPOSE DISALLOWANCES OF CAPITAL EXPENDITURES?

A. Yes. Digital Transactional Experience and Journey Work Product Transformation Teams are two projects that lack sufficient justification to include in rate base in this rate case.

The Digital Transactional Experience entails $6,450,000 of capital expenditures in 2021. This project appears to be a continuation of work initially done in 2020 to fix the Move In/Move Out (MIMO) digital system that allows customers to process their service termination or service start through a self-service option through digital channel when changing service locations. When first implemented the MIMO system did not work properly and customers were frustrated and could not always complete the desired service transfer. On page 43 of her testimony, Ms. Pizzuti discusses the work done in 2020 to fix the systems under the MIMO DEG project name. As it continued with further work and expenditures into 2021, the Company changed the name of the project to Digital Transactional Experience and proposed to spend an additional $6.5 million.

[66] Exhibit AG-1.23 includes DR AG 8.286d, 8.286e, 8.288c, 8.289b, and 8.289c.

In discovery, the Company was asked to explain why additional enhancements are still necessary to this system. In response, the Company identifies features that are rather basic to the operation of the system that should already have been addressed in earlier stages of the overall project. Other listed improvements are vague and difficult to ascertain as to their necessity and value added.[67]

DR AGDE-8.288b also points to a relationship between the Digital Experience Transformation project and the Journey Work Product Transformation Teams project. This project call for $5,368,000 of capital expenditures for the 10 months ending October 2022, and $4,151,000 for the 12 months ending October 2023. The discussion on this project beginning on page 48 of Ms. Pizzuti's direct testimony addresses two component projects the Collection Journey Work Product Transformation Team and the Billing/Payment Journey Work Product Transformation Team. The first appears to be a means for customers to extend the payment due date as a self-service without having to discuss their request with a customer service representative. This appears to be an invitation to higher uncollectible costs not less.

The second project appears to be an undefined project where the digital product teams will find opportunities to "enhance the web experience." It seems that nothing specific has yet been identified for this project to provide any value added. If both projects are directed at reducing customer calls, it would seem that an economic case should be made as to

[67] Id. includes DR AGDE-8.288b.

whether the cost savings justify the capital expenditures to develop more digital systems and features. However, as stated earlier the Company has not performed that financial justification.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The Company has not made a compelling and convincing case the two digital projects discussed above are necessary and create sufficient value to be economically justified. Therefore, I recommend that the Commission remove $6,450,000 of capital expenditures for 2021, $5,368,000 for the 10 months ending October 2022, and $4,151,000 for the 12 months ending October 2023.

F. Corporate Facilities

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S PROJECTED CAPITAL EXPENDITURES FOR CORPORATE-WIDE FACILITIES.

A. On page 1 of Exhibit A-12, Schedule B5.8, the Company forecasted capital expenditures for Corporate Facilities of $136.1 million for 2021, $91.4 million for the 10 months ending October 2022, and $139.9 million for the 12 months ending October 2023. In my review of the proposed expenditures, I have identified several adjustments which I discuss below.

1. Facilities Construction and Upgrades

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR FACILITIES CONSTRUCTION AND UPGRADES.

A. For 2021, the Company forecasted $37,305,000 of capital expenditures for Facilities Construction and Upgrades. In response to discovery, the Company provided actual expenditures for 2019, 2020, and 2021.[68] The actual expenditures for 2021 were $3,172,000 less than the Company had forecasted and included in rate base in this rate case.[69] Therefore, I propose that the $3,172,000 not spent by the Company be removed from rate base. The Company should not be allowed to earn a return and receive depreciation expense recovery on rate base additions that were not incurred.

For the 10 months ending October 2022, the Company forecasted $32,940,000 of capital expenditures. In response to discovery, the Company provided the items that make up the total forecasted capital expenditures for 2022. In reviewing this information, it is apparent that the Company included several ballpark cost estimates for work that may be done in 2022. With no comparable benchmark data provided about the amount incurred in prior years for those items and lacking specific explanations, I developed an alternate estimate for 2022 for this category of capital expenditures by using the average total annual amount

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[68] Exhibit AG-1.24 includes DR AGDE-9.132b.
[69] Exhibit A-12, Schedule B5.2, page 1, line 2, for 2021 = $37,305,000. DR AGDE-9.12b Facilities Construction and Upgrade for 2021 = $34,133,000.

of capital spending during the three years from 2019 to 2021 and then adjusted that average amount for inflation for 2022 and 2023.[70]

The result of my calculations is a forecasted capital expenditures amount of $30,050,000 for the 10 months ending October 2022. This amount is $2,890,000 less than the $32,940,000 forecasted by the Company for the same period. Therefore, I recommend that the Commission remove $2,890,000 from the capital expenditures forecasted by the Company in this rate case.

For the 12 months ending October 2023, I used the same approach and calculated a forecasted amount of capital expenditures of $36,040,000.[71] This amount is $2,919,000 less than the Company's forecast and I recommend that the Commission remove that amount from the Company forecasted capital expenditures.

2. Facilities Renovation

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR FACILITIES RENOVATION.

A. For 2022, the Company forecasted $10.0 million of capital expenditures for renovations, primarily to its corporate headquarters building.[72] In response to discovery, the Company

[70] Three-year (2019-2021) average amount of $34,840 x 1.035 = $36,059 x 10/12 = $30,050 for the 10 months ending October 2022.
[71] 2022 inflation adjusted amount of $36,059,000 x 1.026 = $36,997,000 for calendar year 2023. The sum of $36,050,000 x 2/12 and $36,997,000 x 10/12 = $36,040,000.
[72] Exhibit AG-1.24 includes DR AGDE-9.132b Facilities Renovation

stated that a significant number of employees continue to work remotely with no near-term plans for all remaining employees to return to their original office locations. The Company also reported that it plans to begin a workspace arrangement with fewer dedicated workstations and more sharing of workstations. Given the uncertainty of how office space will be used in the next two years, it makes little sense to spend $10 million on renovations to office space in 2022.

Therefore, I recommend that the Commission remove capital expenditures of $8,333,000 for the 10 months ending October 2022, and $1,667,000 for the 12 months ending October 2023.

3. Service Center Optimization

Q. PLEASE DISCUSS THE ADJUSTMENT REQUIRED TO CAPITAL EXPENDITURE FOR SERVICE CENTER OPTIMIZATION PROJECTS.

A. On page 56 of her direct testimony, Company witness Theresa Uzenski stated that the Company had decided to cancel the relocation of the Wixom pole yard which had been estimated at a cost of $5.0 million, with $4.5 million included in the projected test year. In response to discovery, the Company confirmed that although the project had been cancelled the capital expenditures still remained in the filed exhibits and in rate base.

Therefore, an adjustment needs to be made to remove the $4.5 million from the 12 months ending October 2023.

In total, for the three categories of capital programs discussed above, I recommend that the Commission remove capital expenditures of $3,172,000 for 2021, $11,223,000 for the 10 months ending October 2022, and $9,086,000 for the 12 months ending October 2023.

4. Headquarters Energy Center

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURES DISALLOWANCE THAT YOU PROPOSE FOR THE HEADQUARTERS ENERGY CENTER.

A. On page 58 of her direct testimony, Ms. Uzenski discusses the Company's headquarters new energy center and the cost overrun that occurred with the project. In her testimony, Ms. Uzenski states that although under the initial proposal and cost estimate, the energy center project was justified by a favorable net present value of cost savings above the project cost. However, now with the $8.4 million cost overrun the project is no longer economically justified. Despite this fact, she still argues that the benefits of the new energy center exceed the cost of continuing to receive steam service from Detroit Thermal.

In response to a discovery request, the Company identified the reasons for the cost overrun with the related dollar amounts. Two of largest reasons for the $8.4 million cost overrun were $3.9 million for a revised cost for new gas service and $1.3 million of DTE project management.[73] Both of these cost overruns were within the control of the Company and involved Company employees or affiliated entities. Customers should not pay for those

[73] Exhibit AG-1.25 includes DR STDE-8.1a.

higher costs. The Company has not justified why its own project management costs exceeded previous cost estimates and why the cost of installing gas service to the facility would increase by $3.9 million. The project was approved by the Commission based on the initial cost estimate and the Company needs to be held accountable for cost overruns within its control.

Therefore, I recommend that the Commission remove $5.2 million from rate base in this rate case for cost overruns in 2021 related to the two items discussed above.

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, unnecessary or unsupported.

Summary of AG Disallowed Capital Expenditures		
		Amount **(millions)**
Contingent Capital Expenditures	$	2.1
Distribution Operations		529.7
Power Generation		271.4
Nuclear Operations		38.5
Customer Service		58.7
Corporate Facilities		28.7
Total	**$**	**929.1**

Based on my analysis and information presented in my testimony above, the Commission should reduce the Company's proposed capital expenditures by $929.1 million and average rate base by $679.9 million. Exhibit AG-1.26 provides additional details and calculations of these amounts.

V. Cost of Capital

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-1.27 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 October 2022. 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-20561.

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

A. No.

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 5.26%, which includes a return on common equity of 9.50%, as shown in Exhibit AG-1.27.

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

A. I have utilized the 3.69% 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 have utilized the cost rates recommended by Company witness Lepczyk. For JDITC, I have utilized the long-term debt and common equity rates applicable to this case.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-1.27?

A. To develop the overall cost of capital on line 11, column (f), I have 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 have 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 5.26%.

Regarding the pretax weighted cost of capital on line 11, column (h), I have multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income and other taxes paid by the Company for calculation of the pretax weighted cost of 6.58% 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 indicated that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that being made at the same time…on investments in other business undertakings which are

> attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties….

The principles 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-1.28.

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 been generally accepted by regulatory commissions in other jurisdictions in the United States. Also, I have 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-1.28 shows a calculated cost of common equity of 9.17%, from the three approaches, I recommend an allowed rate of return on equity of 9.50% for the reasons explained later in this section of my testimony. 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 on my Exhibit AG-1.33, to develop my peer group, I started with the 37 electric utility companies followed by the Value Line Investment Survey. From this group of companies, I eliminated six companies due to size considerations which includes Duke, Exelon, and Southern Company (larger companies), as well as three companies with annual revenues at $1.0 billion or less (MGE, Otter Tail, and Until). Next, I eliminated 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 Eversourse Energy, Edison International, and the Southern Company, mentioned above. These companies face higher risks due to wildfire liabilities, nuclear generating plant construction, and the construction of off-shore wind electric generating facilities. Several other companies I disqualified are involved in M&A activity or reorganizations or are companies facing earnings growth challenges.

Exhibit AG-1.33 shows the starting group of utilities with the analysis to arrive at the proposed peer group of companies. The result is the group of thirteen companies shown in Exhibit AG-1.29, all of which have growing earnings and dividends.

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

A. The Company has developed a larger peer group of 27 companies, which are electric utility companies. However, the Company has also sponsored another peer group of sixteen gas distribution and water utility companies which I will address later.

The Company's electric peer group presented by witness Bente Villadsen consists of a group of 27 companies shown on page 35 of her testimony. This group includes eleven of the companies in my peer group plus (a) five companies I eliminated due to size considerations; (b) four companies that are looking to sell assets which are American Electric Power, Entergy, OGE Energy, and Public Service Enterprise Group; (c) six companies with earnings growth challenges which are CenterPoint, Hawaiian Electric, Nextera, Northwestern, Pinnacle West, and Public Services Enterprise Group; (d) DTE Energy, which is inappropriate because it is the parent company of DTEE, whose cost of equity is being evaluated in this rate case; and (e) Edison International (uninsured wildfire risk and thus dividend risk), and Southern Company, which is facing major challenges constructing two new nuclear generating facilities. Edison International has taken after-tax charges to earnings of $3.8 billion[74] for wildfire and mudslide damages in 2021 and prior years. Southern Company's utility Georgia Power has written-off $2.0 billion of nuclear construction cost overruns in the 2020-2021 period.[75]. Those two companies have

[74] See Edison International 2021 Form 10-K, page 10.
[75] See Southern Company 2021 Form 10-K, page II-95.

extraordinary and unique risks in the industry and should not be included in the group of peer companies.

Q. PLEASE COMMENT ON THE COMPANY'S NATURAL GAS/WATER PEER GROUP.

A. The Company has proposed an additional group of purported peer companies for DTE Electric that consists of eight water companies and eight natural gas companies for a total of sixteen additional companies. Five of the eight water companies have small operations with less than $600 million in annual revenues. One of the eight natural gas companies also is relatively small with approximately $500 million in annual revenues. As such, the small market capitalization of some of these companies creates a cost of capital mismatch with the cost of capital of a larger electric utility, such as DTEE. Smaller companies tend to have a higher cost of capital because of their limited ability to withstand business risks and raise capital in the financial markets.

Q. WHAT OTHER PROBLEMS DO YOU SEE WITH THIS PEER GROUP?

A. The water industry is in a state of consolidation. For example, American Water Works, the largest water company selected by witness Villadsen, is a well-known industry consolidator with its earnings growth being highly dependent on achieving synergies by absorbing smaller companies.

Some of the natural gas companies chosen by witness Villadsen have substantial non-utility businesses. For example, Chesapeake Utilities has 36% of its revenues in unregulated businesses, such as propane, natural gas marketing, and midstream services.

Q. WHY DID WITNESS VILLADSEN INCLUDE A SEPARATE WATER AND GAS PEER GROUP?

A. She provides no explanation for this additional proxy group. However, on page 32 of her testimony (lines 15 to 17) she points to certain similarities between electric utilities and the gas and water proxy group which she indicates are "regulation," "serving customers through a network or assets," and the "capital intensive nature" of these industries. These reasons are not compelling.

Furthermore, the additional group of water and natural gas companies is not necessary given the availability of a sufficiently large number of public electric utility companies that offer a better match to the electric business that DTEE is in.

Q. ARE THERE DIFFERENT FINANCIAL CHARACTERISTICS BETWEEN WITNESS VILLADSEN'S ELECTRIC PROXY GROUP AND THE GAS AND WATER PROXY GROUP?

A. Yes. As can be seen in witness Villadsen's Figure 10 on page 35 of her testimony, the average market capitalization of her electric group is $28.1 billion. In contrast, the average market capitalization of the gas and water peer group is just $5.8 billion, or nearly one-fifth of the electric group, as shown in her Figure 11 on page 37 of her testimony. Moreover, five of the eight water companies are smaller operations with less than $600 million in annual revenues and the market capitalization of these five companies ranges from $357 million to $1.97 billion.

Q. DID THE COMMISSION FIND WITNESS VILLADSEN'S PROPOSED GAS AND WATER PROXY GROUP TO BE RELEVANT IN ANY OF THE COMPANY'S PRIOR ELECTRIC RATE CASES?

A. No. As far back as the Commission's order in Case U-18999, the Commission has noted its concerns with including water companies in proxy group results in electric rate cases.[76] Similarly, in Case U-20561, the ALJ indicated that the Company had not established the reasonableness of including gas and water companies in its proxy analysis.[77]

The Company has not presented any new arguments in this rate case that would dissuade the Commission from its prior rulings.

Q. DO YOU BELIEVE THAT THE COMPANY'S PEER GROUPS ARE APPROPRIATE?

A. No. The electric peer group sponsored by the Company is seriously flawed. First, as noted above, it contains two very high-risk companies which are Edison International and

[76] See page 53 of MPSC rate order in Case U-18999.
[77] See page 302 of ALJ PFD in Case U-20561

Southern Company. Second, four of the companies are in the process of selling assets and reorganizing which are American Electric Power, Entergy, OGE Energy, and Public Services Enterprise Group. Third, two of the proxy companies are small—MGE and Otter Tail. As such, nearly 30% of the Company's electric peer group have significant shortcomings and have little in common with DTE Electric in determining the cost of equity capital.

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

<u>Discounted Cash Flow (DCF) Approach</u>

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 and this equation is:

$$R = D/P + g$$

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

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-1.29. 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 ending on April 11, 2022. The annual dividend in column (d) is the average projected dividend level for 2022 and 2023 as calculated by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on Value Line 2022 projections of earnings per share through the 2025 – 2027 period, and Yahoo Finance analysts' projected growth in earnings per share over the next five years. The resulting calculation of the DCF Method indicates an average required return on common equity of 9.18% for the proxy group.

Witness Villadsen presents her simple DCF results in summary form on page 45 of her testimony which are 10.4% for her electric peer group and 11.1% for her water and gas peer group.

Q. **PLEASE EXPLAIN WHY WITNESS VILLADSEN'S DCF COST OF EQUITY IS SO MUCH HIGHER.**

A. Witness Villadsen is utilizing the After-Tax Weighted Cost of Capital (ATWACC) approach that the Company has sponsored in several of its rate cases in recent years.

It is important to realize that this approach starts with calculating a conventional DCF cost of equity and then running the results through an ATWACC process to derive a higher DCF cost of common equity. The outcome is summarized in the table below.

	Electric	Water/Gas
Initial Calculation of DCF Cost of Equity	9.4%	9.7%
Upward Adjustment – ATWACC Process	1.0%	1.4%
ATWACC DCF ROE	**10.4%**	**11.1%**

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

A. The key factor causing the escalation in the ATWACC ROE is the use of the stock market value to book value of the common equity for each company in the analysis. The resulting effect of this ATWACC approach is that the high stock market to book ratios in the utility industry, due primarily to high ROEs vs. low interest rates, artificially inflates the cost of common equity. This is a major fault of the ATWACC approach that, if embraced by regulatory commissions, would lead to higher inflated ROEs awarded in rate cases.

As such, 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 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 in the utility industry. In fact, Company witnesses in prior rate cases have only been able to cite a hand-full of instances where it has been used. 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 calculating the DCF cost of common equity.

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. However, it also relies upon judgments of growth prospects of security analysts, which may or may not be consistent with the beliefs of investors. I will point out that the forecasted growth rates for the proxy group include some high growth rates which in some cases are as high as10.5%. These high growth rates appear to be the result of a temporary rebound in earnings from a low point in recent years. While these earnings may materialize in the short term, such high rates are not sustainable long-term growth rates for electric utilities given that customer and 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 in the DCF results when considered in conjunction with the results of other approaches to determining the cost of common equity.

<u>Capital Asset Pricing Model Approach</u>

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-1.30 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-1.30 shows the results of the CAPM method based upon (1) a projected 3.20% risk free rate as explained below; (2) Beta information available from Value Line; and (3) the Historical Market Risk Premium (R_p) of 7.25% based on the Ibbotson Classic Yearbook.

Normally, I would use a historical risk-free rate (the current yield on 30-year treasury bonds) which as of April 29, 2022, is approximately 2.9%. However, sentiment in the market is fairly universal that interest rates, which have been rising, will continue to rise assuming the Federal Reserve Bank's efforts to contain inflation will push up interest rates. The most recent projection of interest rates available to me is from Kiplinger[78] as of April 15, 2022. Kiplinger reports that the ten-year U.S. Treasury bond will reach the 3% level by the end of 2022 anticipating several increases in the federal funds rate over the balance of 2022. To this 3% level, I added 20 basis points which is the average spread between 30 year and 10-year U.S. Treasuries during March 2022 and the first half of April 2022. The

[78] Kiplinger is an economic data reporting service.

result is a 3.2% projected 30-year US Treasury bond rate at year end 2022. In comparison, the Company used a lower projected risk-free rate of 2.73%. Therefore, my projected risk-free rate is more beneficial to the Company by about 50 basis points.

As shown in Exhibit AG-1.30, I have added the beta adjusted peer group risk premium of 6.19% to the 3.2% risk-free rate to arrive at the 9.39% 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 10.4% TO 11.5%.

A. In Figure 14 on page 42 of her direct testimony, witness Villadsen presents 6 different CAPM estimates for her electric sample group and another 6 CAPM estimates for her water and gas group. In addition, she presents an equal number of estimates under her ECAPM approach. The Commission should not rely upon any of these CAPM and ECAPM results, because all of the estimates have been determined utilizing either the Hamada approach with leveraged betas or the ATWACC process. Both of these methodologies lead to faulty and inflated results.

Witness Villadsen presents two scenarios in her table in Figure 14. Scenario 1 starts with the development of CAPM results for each peer group company on the basis of using a market risk premium (MRP) of 7.25% and a projected 20-year U. S. Treasury bond rate of

2.73% as the risk-free rate. Up to this point the result is close to a traditional approach. The problem is the ATWACC adjustment that witness Villadsen applies afterwards.

Scenario 2 is the same as Scenario 1, except that witness Villadsen uses a 7.89% MRP, which is 64 basis points higher than she used in Scenario 1. The use of an MRP rate of 7.9% versus 7.25%, which is the historical average rate from 1926 to 2020, is unconventional and is based upon witness Villadsen's use of a projected Beta from Bloomberg that she obtained around the time she prepared her testimony and exhibits. The use of such a Beta is inappropriate because it reflects the circumstances in the market at a very short point in time which have now changed due to higher interest rates and lower stock prices.

The following table shows the calculation of my CAPM results and the Company's CAPM results from the first line of its Figure 14 (page 42 of Villadsen testimony) and shows the impact of the ATWACC conversion process.

		Figure 14 Line 1 Result	
	AG Results	**Scenario 1**	**Scenario 2**
Beta used in analysis	0.85	0.91	0.91
Market Risk Premium (MRP)	7.25%	7.25%	7.89%
Beta x MRP	6.19%	6.60%	7.18%
Risk Free Rate	3.20%	2.73%	2.73%
Sub Total (Before ATWACC)	**9.39%**	**9.33%**	**9.91%**
Value of ATWACC Conversion	0.00%	1.47%	1.59%
Total CAPM Result	**9.39%**	**10.80%**	**11.50%**

The use of an average beta on 0.91 by witness Villadsen reflects the inclusion of betas for CenterPoint Energy, Edison International, OGE Energy, and Sempra Energy, with betas ranging from 1.0 to 1.15. As I stated earlier, these companies are not comparable to DTEE for calculation of the cost of common equity. Also, the use of the higher risk premium of 7.89% and the ATWACC conversion process is unconventional and inappropriate.

Additionally, witness Villadsen recommends that a further upward adjustment to the CAPM results should be considered by the Commission under the ECAPM method. She proposes adding an additional 0.1% to 0.2% under the ECAPM. This adjustment is subjective, unconventional, and not supported.

In her testimony, witness Villadsen did not state whether the ECAPM was utilized to set rates in other jurisdictions. However, in Case U-18999 the Company was asked to "provide a list of the cases that the Company witness had been involved with where the regulatory commission expressed its support of ECAPM as a means to establish an ROE outcome." The only specific regulatory commission identified was the Alberta Utilities Commission of Canada and its order of October 7, 2016.[79] That regulatory commission noted on page 45, paragraph 199 of the order that the ECAPM *"…appears to be a model that could contribute to the Commission's determination of a fair allowed ROE…."* However, later in the same paragraph, that commission noted the high degree of judgment required by the ECAPM methodology and the Alberta Commission added this statement**:**

[79] Case U-18999, DTE Gas response to discovery response AGDG-5.191.

"Consequently, the Commission will not rely heavily on the ECAPM results in this proceeding…" (Emphasis added).

While witness Villadsen's various methods used to calculate the cost of equity capital are inventive, they are highly unconventional, not generally accepted, and are based in part upon her opinion that risk levels have permanently risen since the 2007-2008 financial crisis. The Commission should reject these alternative approaches for the reasons previously discussed, which clearly reflect an attempt to inflate the Company's true cost of common equity.

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-1.31 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 8.93%. To arrive at this result, I have used the 4.35% historical spread of electric utility common stock returns relative to utility bonds. Also, I have used a 1.38% (BBB rated) average spread for 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 3.20% 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 45 THROUGH 47 STARTING UNDER THE HEADING "RISK PREMIUM APPROACH AND COST OF EQUITY ESTIMATE" ON PAGE 45?

A. Witness Villadsen indicates in her testimony that she has compared authorized ROEs from electric utility rate case decisions from 1990 to 2021 and compared these ROEs to 20-year U. S. Treasury bonds. She has run a regression model with this data and found a strong relationship and also observed that ROE rates have fallen more slowly than treasury bonds. Based on her model results she states that the return results of her model show that an ROE of 9.9% for a vertically integrated utility would be appropriate based on a recent 20-year U. S. Treasury rate of approximately 3.0%.

What is troubling about this analysis is that it lacks any comparison of the actual returns of utility stocks to treasury bonds and suggests that treasury bond yields are the primary driver in ROE decisions by regulators. 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 due to the accommodative stance of the U.S. Federal Reserve Bank during 2020 and 2021 by reducing interest rates. More recently, in late 2021 and early 2022, inflation has become a concern. To combat this threat, the Federal Reserve Bank has pledged to increase short term interest rates and has indicated that it will reduce the size of its balance sheet of assets of $9 trillion in early 2022 by approximately 1% per month, with this action expected to increase long term interest rates.

In my calculations on the cost equity in this rate case for both the CAPM and Utility Risk Premium methods, I have reflected those expectations with a projected 3.2% risk free rate. As stated earlier, the Company projected a risk-free rate of 2.73%. As of late April 2022, the actual 30-year U.S. Treasury rate is 2.9%. Nonetheless, the Company's access to the capital markets has remained strong as witnessed by DTE Electric's issuance in April 2021 of $425 million of new 30-year long-term debt at a rate of 3.25% and $575 million of 7-year debt at a 1.9%. 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 November 2021 issuing approximately $280 million of 60-year long-term debt at a rate of 4.375%.

Accordingly, the Company's recommendation that the authorized rate of return on common equity should be increased to 10.25% is unsupportable and is largely based on unconventional methodologies applied to CAPM and DCF cost of equity calculations. The results of my DCF analysis, CAPM analysis, and Utility Risk Premium Approach point to a calculated cost of equity closer to 9.2%.

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE GRANTED IN 2020 AND 2021?

A. Since 1990, return on equity rates, granted by regulatory commissions in the U. S., have been in a steady decline from over 12.7% in 1990 to approximately 9.5% in 2020 and 2021.

Pages 1 and 2 of Exhibit AG-1.32 shows the most recent ROE decisions for several companies with ROE rates granted below 10%. The ROE rates range from a low of 8.25% to a high of 9.9% with DTE Electric and Consumers Energy having the highest rates in the under 10% ROE group of utilities. The average for the group is 9.32% in 2020 and 9.44% in 2021.

Page 3 of the exhibit is a summary of all ROE rates granted, including those at 10% and above which in 2020 and 2021 was limited to six companies in California, Florida, Wisconsin, and Iowa. According to Value Line, two of these companies, San Diego Gas and Electric, and Southern California Edison, will have their ROE rates adjusted in 2022 to 9.6% and 9.7%, respectively.[80] Also, the Florida rate of 10.6% shown on page 3 of my exhibit AG-1.32 is for Florida Power and Light and reflects a multi-year rate agreement through 2026 with limited future rate increases. Inclusive of these additional utilities, the overall average ROE rate was 9.39% in 2020 and 9.51% in 2021, or an average of 9.45% over the two years.

[80] Value Line Investment Survey pages 2203 and 2210 dated April 22, 2022.

The information provided in this exhibit is based on ROE rates granted by state regulatory commissions in general rate cases for electric utilities during 2020 and 2021 and published by Regulatory Research Associates, a respected and independent regulatory research firm.

Exhibit AG-1.32 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 10%.

Q. WOULD A REDUCTION IN THE COMPANY'S ROE TO 9.5% HAVE AN IMPACT ON THE COMPANY'S DEBT RATINGS?

A. It is unlikely that a downgrade would occur simply due to a 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 22.4% CFO pre-WC to Debt ratio in 2020. This is a key ratio that Moody's uses to evaluate the Company's credit worthiness. It is Moody's position that ratio results under 20% for a sustained time could lead to a downgrade of the Company's debt.

In Exhibit AG-1.35, I calculated a pro-forma CFO pre-WC to Debt ratio based on the Company receiving and earning an ROE rate of 9.50%. The calculations in the exhibit start with the actual ratio for 2020 and the adjustments needed to reflect a 50% common equity ratio and a 9.50% ROE rate. After making these adjustments the CFO pre-WC to

Debt ratio would decline by an insignificant percentage from 22.4% to 22.2%, which is well above the 20% long-term downgrade threshold set be Moody's.

Q. **ON PAGES 49 TO 51 OF HER DIRECT TESTIMONY, WITNESS VILLADSEN CHARACTERIZES DTE ELECTRIC AS HAVING A HIGHER RISK PROFILE THAN THE ELECTRIC PEER COMPANIES DUE TO THE DETROIT SERVICE TERRITORY AND ITS OWNERSHIP OF THE FERMI NUCLEAR POWER PLANT. WHAT IS YOUR VIEW?**

A. On pages 50 and 51 of her testimony. witness Villadsen describes the Detroit service area as being "economically challenged" and states that she regards the ownership of Fermi 2 as one more fact indicating that the Company is riskier than the sample of peer companies.

Witness Villadsen presents no evidence to support these statements. First, witness Villadsen states that the unemployment rate in Detroit is 6.2% versus the national rate of 5.9%. This is an immaterial difference. Moreover, in discovery the Company disclosed that only 10% of its sales to residential customers are in the City of Detroit.[81] This again is not a significant factor given that many of the other utilities in the Company's peer group also serve urban areas with depressed economic areas.

Second, witness Villadsen's comment on the risk posed by DTEE's ownership of the Fermi 2 generating facility is unsupported. In response to discovery, she stated that she

[81] Discovery response AGDE-2.30a.

had not done an analysis of nuclear risk posed by Fermi 2 to DTEE versus the electric peer group of companies.[82] Her response merely states that nuclear plants are larger plants and risks of nuclear power plant are asymmetric. In other words, she did not have anything specific or useful to add to her general comment. As such, her comments about DTEE having a higher risk profile than other utilities are unsupported and meaningless.

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 pages 18 to 20 of her testimony suggesting that the VIX is somehow relevant. In response to discovery, she stated that she had no projection of the VIX for the projected test year.[83]

The key point 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

[82] Discovery response AGDE-2.35b.
[83] Discovery response AGDE 2.32.

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-1.36, I have included a Value Line Funds article written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not risk. Mr. Appel goes on to say later in this article that "…volatility is only risk if you act during down times, that is, only if you sell a stock."

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 0.85 of the utility peer group used in the CAPM ROE rate calculation discussed earlier. This is in contrast with the general stock market value 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 THE COMMISSION SHOULD USE IN THIS CASE.

A. In Exhibit AG-1.28, I summarized the cost of equity rates from the three methods I used. The range of returns for the industry peer group is from 8.93% at the low end, using the Utility Risk Premium approach, to 9.39% at the high end using the CAPM approach.

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, which in my analysis is 9.18%. In this regard, on line 4 of Exhibit AG-1.28, I have 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 9.17%. To this base cost of equity capital, I have added an additional premium adjustment of 33 basis points to arrive at a recommended ROE rate of 9.50% for DTE Electric in this rate case for the reasons explained below.

First, the current state of the economy and financial markets has increased business risk. The 33 basis points I have added to the calculated cost of equity provides a cushion to absorb the impact of potentially higher business risk and higher interest rates not currently reflected in utility stock prices and forecasted interest rates. I will point out that financial markets and stock prices are already anticipating higher interest rates being set by the Federal Reserve. The 9.50% ROE rate I proposed goes beyond current market expectations. Therefore, there should not be a need for the Commission to add even more of a cushion by setting an ROE rate above 9.50% or even approaching the 9.90% currently authorized for the Company.

Second, I understand that the Commission would be reluctant to grant a ROE at the 9.17% as the true cost of capital at this time, preferring instead a more gradual reduction. The 9.50% ROE rate I have proposed is a reasonable reduction from the last ROE rate of 9.90% granted to the Company approximately two years ago. Michigan utilities currently enjoy some of the highest ROE rates among utilities in country. As shown in Exhibit AG-1.32, ROE rates granted to Michigan utilities in 2020 and 2021 are at the highest end of the range among most utilities in the country and well above the average rate of 9.45%. 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.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE OF 9.50% 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 its strong ability to attract capital in addition to being compensated for risk. Pages 1 and 2 of Exhibit AG-1.32 show several utilities that have accessed the capital markets at competitive interest rates since receiving an ROE substantially below 10% as well as below the average rate of 9.45%.

Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs below 10%. On the contrary, stock investors continue to migrate to utility stocks recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-1.33 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past few years reflecting ROEs ranging from 8.38% to 9.90%. Yet this group of companies has an average ratio of Market price to Book common equity value of more than 2 times book value.

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 9.50%. Therefore, this issue is another “red herring”

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 9.50%?

A. If the Commission were to grant a 9.90% ROE in this case versus a 9.50% ROE, the additional cost to customers is approximately $45.5 million annually. 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 9.50%.

VI. Sales Revenue Adjustment

Q. PLEASE DISCUSS YOUR PROPOSED REVENUE ADJUSTMENT AND EXPECTED HIGHER SALES FOR THE FORECASTED TEST YEAR.

A. Through the direct testimony of Company witness Markus Leuker, the Company forecasted total electricity sales of 45,047 Gigawatt hours (GWh) for the November 2022 to October 2023 test year. The test year forecast represents an overall increase in electricity sales of 1,045 GWh, or 2.4%, in comparison to the weather-normalized actual sales of 44,002 GWh in 2020.[84] The following table shows a comparison by major customer class.

Table 5

Sales in GWh	Projected Test Year Forecast	2020 W/N Actual	Change
Residential	15,114	15,947	(833)
Small C&I	10,778	10,080	698
Large C&I	18,950	17,755	1,195
Other	205	220	(15)
Total	**45,047**	**44,002**	**1,045**

[84] Exhibit A-5, Schedule E1, pages 1, for 2020, and Exhibit A-15, Schedule E1, page 1, for the projected test period.

The 2020 sales volumes were greatly impacted by the Covid-19 pandemic and resulting lockdown of businesses during several months of the year. The business lockdown reduced electricity sales to commercial and industrial customers. However, residential sales surged as individuals and families spent more time at home using more electricity than usual. As readily apparent from Table 5, the Company forecasted a return of a significant volume of sales to commercial and industrial customers during the projected test year and a reduction in residential sales on the assumption that many individuals and families have returned to the work location and resumed pre-covid activities. Although to some degree there has been a return to more normal pre-covid activities and electricity usage, Table 6 below is instructive.

Table 6

Sales in GWh	Projected Test Year Forecast	2021 W/N Actual	2020 W/N Actual	2019 W/N Actual
Residential	15,114	16,122	15,947	14,820
Small C&I	10,778	10,714	10,080	10,877
Large C&I	18,950	18,390	17,755	20,299
Other	205	216	220	226
Total	**45,047**	**45,442**	**44,002**	**46,222**

Table 6 shows that despite the fact that many residential customers have returned to their pre-covid work location, weather-normalized residential sales still surged in 2021 from the higher 2020 level. The 2021 sales data is strong evidence that many customers are still working from their home location and the average electricity usage per customer is increasing to more than compensate for those customers who have returned to their original work location.

Table 7 clearly shows this phenomenon of higher electricity usage by the average residential customer in 2020 and not only continuing but increasing in 2021 despite any energy usage offset from the Company's energy waste reduction program.

Table 7				
	Residential		Average Use	
	W/N Sales		Per Customer	Change Over
Year	GWh	Customers	kWh	Prior Year
2016A	15,182	1,966,675	7,719.6	
2017A	14,979	1,980,151	7,564.8	-2.0%
2018A	14,935	1,991,879	7,497.9	-0.9%
2019A	14,820	2,003,542	7,396.9	-1.3%
2020A	15,947	2,019,744	7,895.4	6.7%
2021A	16,122	2,036,578	7,916.1	0.3%
2022F	15,326	2,048,950	7,480.1	-5.5%
2023F	15,124	2,061,026	7,338.2	-1.9%
PTY	15,114	2,059,058	7,340.1	-7.3%

The average residential customer electricity usage surged in 2020 to 7,895 kWh and surged again in 2021 to 7,916 kWh. In contrast, the Company has forecasted a decline in usage per customer to 7,480 kWh in 2022 and a further decline in 2023 and the projected test year.

Table 6 above, which compares the projected test year sales forecast to prior year weather-normalized sales, is very revealing. Based on the continued high average usage per customer the decline in residential sales to 15,114 GWh in the projected test year forecasted by the Company does not seem warranted. Although the Company has projected that small commercial and industrial sales in the projected test year will return to near the sales level of 2019, the large commercial and industrial class is still lagging by about 350 GWh. Part of this shortfall is some loss of industrial load due to plant shutdowns and shift to self-generation, the remainder appears to be the result of a conservative forecast.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECASTED SALES FOR THE PROJECTED TEST YEAR?

A. Although the sales forecast for both classes of commercial and industrial customers may still be somewhat conservative, I generally find it to be reasonable and I will not dispute the Company's forecast for those classes of customers. However, with regard to the residential customer class, I find the Company's forecast unreasonably low. As stated above, the Company has calculated a forecast that assumes a decline in average customer usage to a level even below the usage in 2019 when recent evidence in 2021 shows that electricity usage per average customer continues to surge.

Q. IS THERE A POTENTIAL EXPLANATION FOR THE DECLINE IN THE RESIDENTIAL CUSTOMER USAGE FORECASTED BY THE COMPANY?

A. Yes. On page 13 of his direct testimony, Mr. Leuker describes a "wedge" adjustment that he incorporated in his sales forecasting model to compensate for variations in sales volumes since the beginning of the Covid-19 pandemic. In response to discovery, Mr. Leuker disclosed that the Company utilized data compiled from Community Mobility Reports sourced from Google Maps and other sourced data, to strike a correlation between the movement of individuals from home to businesses and other activities to and from business locations. Although not fully explained, Mr. Leuker developed factors that adjusted historical baseline customer consumption based on the Google Mobility trends compiled since the start of the Covid pandemic and in comparison to more recent activity. Exhibit AG-1.37 includes several discovery responses pertaining to the mobility data.

Although Mr. Leuker's "wedge" adjustment is a novel approach, it is not a proven methodology. This is the first time that it has been tried in forecasting sales in a rate case with no prior track record to show that the use of Google Maps mobility data can be an accurate predictor of future electric sales. The Company has not presented any back testing to show that if the mobility data had been used in developing prior year sales forecasts it would have resulted in accurate forecasts against actual results.

At this point, it is a speculative approach. No direct connection has been presented showing that individuals moving around in a certain geographical area will result in changes in their electricity consumption. The link between those factors seems farfetched despite the statistical gyrations that Mr. Leuker's may have done within his model. In fact, the increase in average residential customer usage in 2021, which is past the Covid-19 lockdown, undermines the results of the "wedge" adjustment and the correlation to the mobility data. Therefore, the "wedge" factor used by Mr. Leuker likely understated the forecasted sales for the projected test year and more severely for the residential customer class.

Q. HAVE YOU CALCULATED AN ALTERNATE FORECAST FOR RESIDENTIAL SALES FOR THE PROJECTED TEST YEAR?

A. Yes. Using the most recent average customer usage per customer from 2021 of 7,916.1 kWh, I adjusted that usage level by the Company's EWR target percentage of 1.5% for 2022 and for the 10 months in 2023. The result is an adjusted average residential usage per customer of 7,699.9 kWh for the projected test year. I multiplied this average usage by the number of customers forecasted by the Company for the test year to arrive at projected residential sales of 15,854.6 GWh. Additionally, I adjusted that sales forecast for Distributed Generation purchases made by the Company from residential customers and the additional electric vehicle sales forecasted by the Company. The result is forecasted residential sales of 15,910.4 GWh. In comparison, the Company's forecast of 15,114.0 GWh has understated the projected test year residential sales by 796.4 GWh.

Exhibit AG-1.38 shows the calculations I described above to arrive at the 796.4 GWh incremental sales.

Q. HAVE YOU DETERMINED THE INCREMENTAL SALES REVENUE FROM THE ADDITIONAL RESIDENTIAL SALES YOU FORECASTED?

A. Yes. In Exhibit AG-1.38, I applied the current distribution tariff applicable to residential customers to the 796,436,349 kWh of additional forecasted sales to arrive at the incremental revenue of $52,652,407.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. From the analysis presented above, it is evident that the Company's methodology to forecast sales for the projected test year resulted in significantly understating residential sales for the projected test year. The Commission should reject the Company's novel and unproven approach. Instead, the Company should accept my conventional approach using the most recent residential sales data to calculate an accurate forecast for residential sales for the projected test year.

Therefore, I recommend that the Commission include $52,652,407 of additional revenue in this rate case to reduce the Company's calculated revenue deficiency.

VII. O&M Expenses Adjustments

Q. WHAT AMOUNT OF O&M EXPENSE DID THE COMPANY INCUR DURING 2020 AND WHAT IS THE LEVEL OF PROJECTED EXPENSE REQUESTED BY THE COMPANY FOR THE 12 MONTHS ENDING OCTOBER 2023?

A. As shown in Exhibit A-13, Schedule C5, the Adjusted Historical Test Period expense for Other O&M is $1.261 billion for 2020. The Company has projected that O&M expenses will increase to $1.281 billion during the test year ending October 2023. While the

Company's projected expense level represents a 1.6% increase of $19.6 million over the historical level, there are many offsetting changes that should be noted. First, cost reductions of approximately $124 million were reflected in the projected test year pertaining to the closing of three power plants ($53 million), lower pension expense ($47 million) and an increase in the A&G Capitalized credit ($24 million). Second, offsetting these expense reductions is $78 million of forecasted inflation cost increases for wages and other expenses, and $66 million of expense increases in various other areas.

As a result of my analysis in Exhibit AG-1.40, I have identified $112.1 million of expense reductions, which I will discuss in more detail below.

A. Inflation Adjustments - O&M Expense

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

A. No. Given the similarity in the forecasted rate of inflation I developed from more recent CPI forecasted rates, I do not see a need to make adjustments to the Company's forecasted inflationary cost adjustments. Although I do not agree with the Company's use of a wage inflation rate increase of 3.0% applied to labor costs as a separate rate of increase from the CPI inflation rate applied to non-labor O&M expenses, it would not serve any constructive purpose to present recalculations that would result in only a small expense adjustment. This accommodation is not a change in the position I advocated in previous rate cases against the blended inflationary adjustment to O&M expenses by using forecasted wage increases and a CPI inflation rate. The Commission has agreed with my position in previous rate cases and I still hold that view.

B. Nuclear Extended Power Uprate Study

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO UNDERTAKE A STUDY TO EXTEND THE OPERATING CAPACITY OF THE FERMI 2 NUCLEAR PLANT.

A. Beginning on page 39 of his direct testimony, Company witness Jeffrey Davis proposed that the Company undertake a study to potentially increase the operating capacity of Fermi 2 by 176 MWe. According to Mr. Davis, the Fermi 2 Extended Power Uprate (EPU) Study would assess the viability to increase the operating capacity and required upgrades to existing equipment. To undertake the study, the Company has included $4.9 million in deferred PERC costs for 2023. In response to discovery, the Company stated that the $4.9 million is not the total cost to perform the study but did not disclose what the total cost would be.[85]

Mr. Davis has estimated the cost to achieve the Uprate and incremental capacity of 176 MWe at between $600 million and $1 billion. This significant investment appears to be a very preliminary estimate and could change significantly depending the upgrades needed

[85] DR AGDE-7.223.

to the plant and equipment. At the $1.0 billion cost, the capital investment would translate to a cost per installed MW of capacity of $5.7 million. Even at the low end of the estimated cost, the capacity cost would be $3.4 million per MW. In comparison, the MISO Zone 7 CONE cost of capacity is $94,000 per MW.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSAL TO BEGIN THE EUP STUDY?

A. Given the large disparity in the cost of capacity of the Fermi 2 uprate to the current cost of capacity from other sources, it is not reasonable to undertake a study at this time at a cost of more than $4.9 million. The Company has not made a compelling and convincing case that the study would lead to an outcome that would provide a competitive cost of adding capacity even after considering that the added capacity would be carbon free.

I recommend that the Commission reject the Company's proposal and remove the $4.9 million from the 2023 PERC deferred costs.

C. Distribution O&M Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DISTRIBUTION OPERATIONS O&M EXPENSE FOR THE PROJECTED TEST YEAR.

A. In Exhibit A-13, Schedule C5.6, the Company shows several historical test year adjustments to normalize O&M expense for Distribution Operations. In column (e) of the exhibit and footnote 4, the Company shows an increase in O&M expense of $3,687,000 as one-time expense adjustments. In response to discovery, the Company explained that this amount includes $1,213,000 of costs for 35 employees temporarily loaned to the Customer Service operation.[86]

However, the comparable O&M exhibit for Customer Service does not include the same amount as a one-time reduction to 2020 test year expenses in Exhibit A-13, C5.7. Therefore, there is a mismatch between the Distribution proposed adjustment and the Customer Service area. The one-sided adjustment proposed by the Company is not appropriate and should be removed. Therefore, I recommend that the Commission remove the $1,213,000 from the Company's forecasted O&M expense for the projected test year.

D. Tree Trimming Cost Savings

Q. ARE YOU PROPOSING ANY REDUCTIONS TO THE COMPANY'S PROPOSED SPENDING ON TREE TRIMMING COSTS?

A. No. The O&M and surge program spending for tree trimming proposed in Ms. Hartwick's testimony and exhibits seems in line with prior Commission orders. The Company also has proposed additional spending on tree trimming over the coming three years from the $70 million of Company funds set aside in Case No. U-21128. According to the Company, the total availability of funding for tree trimming should allow the Company to achieve a

[86] Exhibit AG-1.41 includes DR AGDE-2.47a and 7.198a.

5-year clearing cycle ahead of its originally planned date and accelerate related cost savings.

Q. DID THE COMPANY IDENTIFY CERTAIN COST SAVINGS THAT WILL BE REALIZED IN 2022 AND 2023 AS A RESULT OF THE SURGE PROGRAM AND ACCELERATED TREE TRIMMING?

A. Yes. Table 11 on page 36 of Ms. Hartwick's testimony shows certain savings related to the Tree Trimming Surge Program. As discussed in the Capital Expenditures section of my testimony, in response to discovery, the Company provided cost savings for both capital spending and O&M expense for 2022 and 2023. Exhibit AG-1.11 shows this information. Exhibit AG-1.42 shows an analysis 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 2020. Based on the information provided by the Company, the analysis shows that O&M cost savings of $5.7 million can be achieved as a result of the spending on the surge program and related programs.

Therefore, I recommend that the Commission remove the $5.7 million in cost savings from the Company's forecasted O&M expense.

E. Customer Service O&M Expense

Q. PLEASE EXPLAIN YOUR PROPOSED ADJUSTMENTS TO CUSTOMER SERVICE OPERATIONS O&M EXPENSE FOR THE PROJECTED TEST YEAR.

A. In Exhibit A-13, Schedule C5.7, the Company shows an expense adjustment for $1,787,000 in the historical test year in column (f) and footnote 2. In response to discovery, the Company stated that the adjustment pertains to deferred hiring of customer service representatives during 2020 due to reduce call volumes.[87] This adjustment was carried into the projected test year.

Schedule C5.7, in column (k) and footnote 4, also shows that for the projected test year, the Company included $7,920,000 of additional expense to hire 120 additional customer service representatives (CSRs). Company witness Jason Sparks discusses this additional expense on page 25 of his direct testimony. Mr. Sparks attributes the need to add 120 CSRs to more complex calls received from customers for high bills and low-income customer issues, and a desire to improve operational performance and customer satisfaction.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSED ADJUSTMENTS TO O&M EXPENSE FOR THE PROJECTED TEST YEAR.

[87] Exhibit AG-1.43 includes DR AGDE-2.49a.

A. Both of the Company's proposed adjustments pertain to the number of CSRs and employee headcount within the Customer Service operation. In response to discovery, the Company provided the number of employees within the Customer Service operation from 2016 through 2023. The information shows that the number of customer service employees (FTEs) assigned to the electric business increased in 2020 to 744 FTEs from 675 FTEs in 2019.[88] Therefore, it does not appear that there was much if any delayed hiring.

The employee count data also shows further increases in customer service employees in 2021 and 2022 before a levelling at 847 FTEs in 2023. This trend and the request for 120 CSRs proposed by Mr. Sparks is troubling. The Company has spent hundreds of millions of dollars on digital technology, customer system upgrades, and customer service automation systems to supposedly reduce the number of calls that need to be handled by CSRs. Ms. Pizzuti filed nearly 100 pages of testimony touting the advantages of new digital systems and customer self-help tools, and proposed approximately $200 million of new IT systems to reduce customer calls and enhance the "customer experience."

Mr. Sparks' testimony and request for an additional $9.7 million of O&M expense to hire more CSRs is counter to the capital spending proposed by Ms. Pizzuti and the purported advantages of the initiatives that she has proposed. The Company can't have it both ways. It must either reassess its investment in digital and customer self-help systems and avoid those capital expenditures or withdraw its request to add more CSRs.

[88] Id., includes DR AGDE-3.73.

I recommend that at this time, the Commission remove the total amount of $9,707,000 from the Company's proposed O&M expense. The Commission should also direct the Company to provide a cost/benefit analysis in the next rate case that shows the capital expenditures made to date and proposed in the future for customer digital IT systems is reducing operating costs, particularly in call handling and other areas of the Company.

F. Uncollectible Accounts Expense

Q. PLEASE SUMMARIZE HOW THE COMPANY ARRIVED AT ITS PROPOSED $59.0 MILLION EXPENSE FOR UNCOLLECTIBLE ACCOUNTS FOR THE PROJECTED TEST YEAR.

A. Company witness Tamara Johnson discusses the uncollectible expense beginning on page 19 of her direct testimony and also sponsors Exhibit A-13, Schedule C5.8. The exhibit shows that the Company started its calculation of the uncollectible expense for the test year by using three years of booked uncollectible expense from 2017, 2019, and 2020. The Company averaged the three years of expense to arrive at a three-year average amount of $59.6 million and omitted the 2018 year because expenses were extraordinarily high due to problems with the Company's Customer 360 system. I will point out here that the historical amounts represent the uncollectible expense that the Company estimated and recorded on its books in those years and they do not reflect the actual bad debt charge-offs in those years. Later in my testimony, I will discuss how using actual net charge-offs is a sounder approach.

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

I propose to use the commission-approved methodology of a three-year average of charge-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. This approach also works for forecasting the uncollectible expense for the 2023 projected test year due to the fact that the COVID lockdown did not increase charge-offs in any measurable way in 2020 or 2021.

The booked expense for uncollectible accounts can fluctuate from year to year due to a number of reasons including assumptions made by the Company, temporary events, and the adequacy of the reserve account at the outset of any one particular year. Therefore, using booked uncollectible expense, as the Company has done in this case, is not wise or appropriate.

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

For the projected test year, I forecasted uncollectible accounts expense of $50.3 million using the three-year historical ratio of net charge offs to revenue for 2017, 2020, and 2021. I omitted the years 2018 and 2019 due to the Company's suspension of collection activity for several months while it resolved data and systems issues subsequent to the implementation of the Customer 360 system.

Exhibit AG-1.44 shows the net charge-offs for the five-year period from 2017 to 2021 as follows: 49.7 million for 2017, $63.3 million 2018, $71.8 million for 2019, $49.7 million for 2020, and $40.0 million in 2021. As apparent from this data, the 2018 and 2019 net charge-offs increased significantly over the prior year and for years subsequent to 2019. The Company has consistently advocated in prior rate cases that the year 2018 should not be used in any analysis of Uncollectible Accounts Expense due to the suspension in collection activity during 2018. However, the suspension in collection activity also had an impact on 2019 net charge-offs. The Company's policy is to charge-off uncollectible accounts 120 days (four months) after they become past due and uncollectible. The four-month delay in charging off uncollectible accounts from 2018 would increase the amount of charge-offs in 2019.

Therefore, both 2018 and 2019 should be removed from the three-year average calculation due to the unusual circumstances. The calculations I performed in Exhibit AG-1.44 reflect the appropriate way to determine the uncollectible expense for the projected test year.

Line 4 of the exhibit shows the average percentage of 0.91% as the ratio of net charge-offs to revenue for the three-year historical period. This percentage was multiplied by the projected test year revenues of $5.556 billion on line 5 to derive the forecasted amount of uncollectible expense of $50.3 million on line 6.

This amount represents a reduction of $9.4 million from the Company's proposed uncollectible accounts expense of $59.7 million. Accordingly, the Commission should set the expense level for uncollectible accounts expense at $50.3 million and reduce the Company's forecasted O&M expense by $9.4 million.

G. Merchant Fees

Q. DO YOU AGREE WITH THE COMPANY'S FORECASTED INCREASE OF $9.7 MILLION IN RESIDENTIAL CUSTOMER MERCHANT FEES BETWEEN 2020 AND THE FUTURE TEST YEAR?

A. No. Line 3 of Exhibit A-13, Schedule C5.7.1, shows an increase of approximately $9.7 million in residential credit and debit card merchant fees between 2020 and the projected test year. In his direct testimony, Company witness Benjamin Burns provides a brief discussion of merchant fees and sponsors Exhibit A-13, Schedule C5.8, to support the residential customers' merchant fees of $19.1 million forecasted for the test year. In the exhibit, the Company assumes that merchant fees for residential customers will continue to increase at an annual rate of 28.1% based on two years of increases from 2018 to 2020. This results in more than a 100% increase in merchant fees between 2020 and the projected test year.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S RESIDENTIAL MERCHANT FEES PROJECTION?

A. The basic problem with the Company's forecast is that it assumes the rate of increase from 2018 to 2020 will continue unabated into 2021, 2022, and 2023. As more and more customers pay their electric bill with a credit or debit card, there are fewer customers left who will make use of credit and debit cards to pay their bills. This is basic logic. The 2021 actual data support this conclusion. In response to discovery, the Company reported that in 2021 it incurred $9.9 million of residential merchant fees.[89] In comparison to the amount of $9.4 million incurred in 2020, residential merchant fees increased only by 5% between 2020 and 2021.

Q. WHAT IS YOUR FORECAST OF MERCHANT FEES FOR THE PROJECTED TEST YEAR?

A. My projection of residential merchant fees for the projected test year is $11.5 million, as shown in Exhibit AG-1.45.

To better evaluate residential merchant fees, I obtained certain historical information from the Company, such as the amount of electric residential revenue, the amount of residential customer payments made by credit card, and the amount paid in merchant fees for each year from 2016 to 2021.[90] By developing the relationship between total revenues and the amount paid by credit card and also the relationship of the merchant fees paid on those credit card payments, I established a sound basis to evaluate how merchant fees have grown relative to billed revenue and bills paid by credit cards. As shown in Exhibit AG-1.45, the percentage of total residential revenue paid by credits cards has grown from

[89] Exhibit AG-1.46 includes AGDE-2.52a.
[90] Id., included AGDE-2.52b.

26.8% in 2016 to 39.7% in 2021, with an annual growth rate of 2.58%. Based on this growth rate, I forecasted that in the projected test year 44.44% of total revenue will be paid by credit/debit cards.

In Exhibit AG-1.45, I used the Company's projected residential revenues in this rate case and the 44.44% of such amounts paid by debit or credit cards to derive $1.35 billion of revenues subject to merchant fees. Multiplying this result by the 0.85% merchant cost rate resulted in $10.9 million of merchant fees expense. This amount is $8.2 million lower than the Company's forecast of $19.1 million.

The Company's forecast of merchant fees expense is excessive by improperly assuming that the average rate of increase in fees over the 2018-2020 period will continue unabated. Therefore, I recommend that the Commission remove $8.2 million from the Company's projected test year O&M expense.

H. Health Care Expense

Q. THE COMPANY HAS FORECASTED THAT ITS ACTIVE EMPLOYEE HEALTH CARE EXPENSES (MEDICAL, DENTAL, AND VISION) WILL INCREASE FROM $41.4 MILLION IN 2020 TO $58.0 MILLION IN THE FUTURE TEST YEAR. DO YOU AGREE WITH THIS INCREASE?

A. No. There are several problems with the Company's active health care expense projection. First, because of the impact of Covid-19 on the Company's health care costs, adjusting

2020 costs to an appropriate level is extremely difficult. Company witness Cooper attempted this and has created at least one error, which he has since corrected through his revised testimony and exhibits (resulting in a $2.5 million lower expense level). Second, after adjusting for the impact of Covid-19, witness Cooper determined that 2020 costs are $10,566 per employee. However, he then takes a novel and unorthodox approach and increases this cost for 2020 to $11,454 per employee (8.4% higher) by way of a "constant dollar averaging process." With this starting point, he then escalated the health care costs by 5.5% for 2021, 5.0% for 2022, and 4.5% for 2023 using his sourced cost trend rates.

Q. WHAT IS YOUR ASSESSMENT OF THE CALCULATIONS PERFORMED BY MR. COOPER AND THE RESULTING FORECAST?

A. The problem with Mr. Cooper's analysis and calculations is that the $11,454 constant dollar adjusted cost per employee for 2020 is divorced from reality. This amount is $8.4% higher than his adjusted actual cost determination for 2020 of $10,566. Mr. Cooper is simply compounding inflationary increases on top of inflationary increases over the eight-year period from 2016 to 2023. The Commission should not accept this brazen attempt to inflate forecasted O&M expenses.

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

A. Yes. In Exhibit AG-1.47, I calculated a forecasted expense of $48.5 million for the projected test year. To arrive at this amount, I used information obtained from Mr.

Cooper's Exhibit A-13, Schedule C5.11.4, which has the actual average cost of health care per employee from 2016 to 2019 without the constant dollar averaging adjustments. Given the decline in the health care cost in 2020 due to Covid-19 pandemic restrictions and fewer medical procedures performed in that year, I averaged actual 2021 costs with 2020 costs without Mr. Cooper's arbitrary $3.1 million Covid cost adjustment. The two-year average approach considered the fact that many medical procedures and doctor visits were delayed in 2020 into 2021.

My approach of averaging 2020 and 2021 health care costs resulted in an average cost per employee of $10,834, versus Mr. Cooper's calculated cost $10,566. The two amounts are relatively close. Based on the $10,834 cost per employee for 2020/2021, I calculated an average annualized increase in the cost per employee of 2.5% since 2016. The 2.5% average rate of increase already reflects any inflationary increase in costs year over year as actually experienced, and therefore it is not necessary to further inflate it as Mr. Cooper has done.

Using the 2.5% annual rate of increase and applying it to the normalized actual costs in 2020/2021 and subsequent years, I calculated the projected test year expense at $48.5 million after allocating a portion of the costs to capital expenditures. This 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 $58.0 million.[91]

I recommend that the Commission approve the $48.5 million of forecasted health care expense for the test year and remove $9.5 million from the Company's forecasted O&M expense in this case.

I. Pension Expense

Q. WHAT IS THE AMOUNT OF PENSION EXPENSE INCLUDED BY THE COMPANY IN O&M EXPENSE?

A. As shown in Exhibit A-13, Schedule C5.12.0, the Company included $9.1 million of pension expense in the projected test year net of amounts capitalized and deferred. Mr. Cooper discussed the pension plan beginning on page 5 of his testimony.

Q. DO YOU AGREE WITH SOME OF THE RATE ASSUMPTIONS USED BY THE COMPANY IN THE ACTUARIAL ANALYSIS PERFORMED TO CALCULATE PENSION EXPENSE FOR THIS RATE CASE?

A. No. As shown at the top of page 7 of Mr. Cooper's direct testimony, the Company lowered the expected return on assets rate from 7.10% in 2020 to 7.00% in 2021, and continues to

[91] Subsequent to filing Mr. Cooper's direct testimony in this case, the Company filed revised direct testimony and exhibits revising the amount of proposed health care expense to $55.5 million, or $2.5 million lower. However, the Company did not file a revised total O&M expense or revised revenue deficiency reflecting the lower health care cost. To avoid confusion, I used the original health care cost projection at this time.

lower the rate by 10 basis points each year through 2023 down to 6.70%. This declining trend has also occurred in the prior two rate cases. The declining expected return rate on plan assets is not justified by the actual returns earned by the plan assets over the past 12 years. Although actual return can go up and down from year to year. Over the past 12 years, from 2010 to 2021, the Company's pension assets have earned on average return of 8.94%.[92] The 7.00% rate declining to 6.70% assumed by the Company in the actuarial analysis is a far cry from the long-term actual return achieved.

A higher expected return rate will result in lower pension expense for the projected test year. The Company has significant discretion in setting the applicable expected return rates on plan assets within the actuarial analysis. As Senior Vice President of Finance at MCN Energy Group, I had responsibility over similar pension plans and I am very well aware of the actuarial process and how rate assumptions are set within the actuarial analyses.

The Company justifies the declining expected return based on a change in the asset investment strategy to a more conservative mix of investments. However, in response to discovery, the Company provided target asset mix percentages for 2023 that do not change much from the actual mix in 2021. In fact, the opposite has been forecasted by the Company with equity investments increasing from 28.9% in 2021 to 31% in 2023 and

[92] Exhibit AG-1.48 includes DR AGDE-8.263c.

fixed income declining from 47.3% to 45% for the same years.[93] Therefore, the change in investment strategy is not the reason for the declining expected rate of return.

Additionally, as stated on page 6 of Mr. Cooper's direct testimony, the Company used a discount rate of 2.57% within the actuarial analysis to determine the interest costs and pension service costs for the projected test year. This rate was outdated at the time it was used given that in calculating pension cost in the footnotes to the Company's 2021 financial statements included in the Company's Form 10K for 2021, the Company used a higher discount rate of 2.91%. A higher discount rate will result in lower pension expense. With interest rates increasing further in 2022, the 2.91% is also now stale and by the end of 2022, the Company will likely use a higher rate which will further lower pension costs.

Q. DID THE COMPANY PROVIDE A PENSION COST SENSITIVITY ANALYSIS SHOWING HOW PENSION COSTS CAN VARY BASED ON CHANGES IN ACTUARIAL ASSUMPTIONS?

A. Yes. In Exhibit A-13, Schedule C5.12.2, the Company provided a pension cost sensitivity analysis showing how pension costs can vary depending on changes in the asset return rate and the discount rate. The sensitivity analysis shows that by changing the actual return on assets from 7% in 2021 to 12% and changing the discount rate from 2.57% to 3.57%,

[93] Id., includes DR AGDE-8.263b.

pension costs would decline from a positive $13.5 million to a negative amount of $33.7 million.

On the other hand, if the Company were to lower the expected rate of return on assets to 6.0% in 2022 and 2023 from the currently assumed rate of 6.80% and 6.70%, respectively, the negative pension cost would decline by nearly $30 million. Page 10 of Mr. Cooper's testimony explains the same cost changes. This exercise shows the significant impact that rate assumptions have within the pension cost actuarial analysis and justifies the reason why those assumptions should be challenged in a rate case.

In discovery, the Company was asked to perform a similar pension cost sensitivity analysis using the actual plan asset return of 8.4% in 2021, the 2.91% discount rate at year end December 2021, and maintaining the expected rate of return of 7.00% used in 2021 also for 2022 and 2023. The cumulative result is that pension expense for the projected test year goes from a positive amount of $9,145,000 to a negative amount of $8,297,000 for a net change of $17,442,000. Exhibit AG-1.48 includes the analysis provided by the Company in response to DR AGDE-8.270.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The Company's assumptions for the discount rate, the actual return on assets in 2021, and the expected return on assets for 2022 and 2023 are either outdated or unreasonable given more recent information. The outcome of those assumptions is a pension expense for the projected test year that is highly inflated.

Therefore, I recommend that the Commission accept the updated run of pension expense provided by the Company in response to DR AGDE-8.270 included in Exhibit AG-1.48 which lowers pension expense for the projected test year by $17,442,000.

J. 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 October 2023, the Company seeks to recover $63.8 million of employee incentive payments. Based upon the information provided on pages 53 and 54 of the direct testimony of Company witness Michael Cooper, $11.6 million pertains to the Annual Incentive Plan (AIP), $29.1 million to the Rewarding Employees Plan (REP), and $23.1 million pertains to the Long-Term Incentive Plan (LTIP).

2021 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 Operating 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 OSHA Dart Rate).

4. 25% on Operating Excellence (Blue Sky CAIDI, SAIDI Excluding MEDS, Nuclear On-Line Unit Capability Factor (UCF), and Fossil Fuel Power Plant reliability).

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 and only 20% is based on Financial Performance.

These measures described above are for the year 2021. 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.

2021 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.

2021 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 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% DTE Gas Average Return on Equity.

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

The testimony of Company witness Michael Cooper 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, pages 53 and 54 of Mr. Cooper's testimony shows that $41.5 million out of the $63.8 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 2021 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 and CAIDI), 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 program 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 put forth by Mr. Cooper in his testimony 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. COOPER TO JUSTIFY RECOVERY OF THE INCENTIVE PAYMENTS?**

A. In Exhibit A-21, Schedule K6, Mr. Cooper has shown a calculation which purports to show that recent operating and financial cost savings are exceeding adjusted incentive plan payments by $41.9 million. However, the largest benefits showing in this exhibit are in the areas of (1) Financial Measures ($18.5 million); (2) Operating Excellence ($56.6 million) with $41.0 million of this category being highly dependent upon a more aggressive tree trimming program and capital spending program which should in turn reduce the SAIDI and CAIDI outage metrics; and (3) $17.6 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.

Regarding this latter category of benefits, the attachment to discovery response AGDE-2.69 shows that 98% of the benefits relate to achieving productivity. However, contrary to that goal, the Company is planning to increase employee levels by 10.7% between 2019 and 2023, as shown in the table below.[94]

Major Area	2019	2020
DTE Electric	2,415	2,665
Marketing	116	138
Customer Service	976	1,163
Corporate staff	1,935	2,057
Total	5,442	6,023

Therefore, the productivity gains may be fleeting.

Q. PLEASE COMMENT ON THE COMPANY'S PERFORMANCE ON THE OPERATING METRICS IN 2021.

A. In response to discovery, the Company provided the results of the incentive performance measures for the year 2021. The 2021 results show that DTE Electric's performance on 6 of the 8 metrics was below target. Nuclear Generation's performance measures were

[94] DR AGDE-9.301e.

below target in 4 of the 6 metrics, and DTE LLC's performance was below target in 4 of the 7 metrics.[95] On average in 2021, target performance was reached for only one-third of the performance metrics.

Q. DO THE 2021 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. Cooper stated on page 53 of his testimony that the $63.8 million of incentive compensation expense is based on "Target" performance levels. Therefore, if the Company's sub-standard performance levels continues into the projected test period, then a substantial portion of the incentive payments anticipated by Mr. Cooper will not happen.

As shown in my testimony above, the Company was able to only meet one-third of the performance measures during 2021. Also, as can be seen from Exhibit A-21, Schedule K7, the performance results in the 2016 to 2020 timeframe shows many metrics at either below Threshold or below Target. Accordingly, 2021 was not a one-year anomaly.

Mr. Cooper's testimony and exhibits provide little assurance that all operating performance 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.

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[95] See attachment to AGDE 8.272.

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 pages 53 and 54 of his direct testimony, Mr. Cooper 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 $41.5 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 Exhibit AG-1.49, I have calculated the percentage of non-financial metrics achieved at target or better over the past five year ending in 2021. The overall percentage achieved by the three organizations over the five-year period is approximately 60%. The total amount of incentive compensation calculated by the Company at target for operating measures relating to the AIP and REP is $21,225,000, as shown in Table 3 on page 53 of Mr. Cooper's direct testimony. As stated earlier, on average over the past five years, the Company has only been able to achieve approximately 60% of performance measures at target or better. Therefore, I recommend that the Commission only approve recovery of compensation expense for 60% of the $21,225,000 or $12,735,000, and disallow recovery of the remaining amount of $51,028,000.

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 $112.1 million as discussed above and summarized in the following table. Exhibit AG-1.40 provides additional details of the areas where I have proposed O&M expense adjustments.

Summary of O&M Expense Reductions	Amount ($Millions)
Distribution Operations	$ 1.2
Tree Trimming Surge Savings	5.7
Customer Service	9.7
Uncollectible Accounts Expense	9.4
Credit/Debit Card Fees	8.2
Active Health Care	9.5
Pension Expense	17.4
Employee Incentive Compensation	51.0
Total Reduction	**$ 112.1**

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 $28,003,000. The calculation of this amount is shown in Exhibit AG-1.26 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 $28,003,000.

<u>IX. Return on Deferred Tree Trimming Costs</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO APPLY THE PRE-TAX PERMANENT COST OF CAPITAL IN CALCULATING THE RETURN ON TREE TRIMMING DEFERRED COSTS?

A. In Exhibit A11, Schedule A1.1, the Company shows the calculation of the return on the average balance of the regulatory asset established to defer tree trimming surge costs until they are securitized. In Schedule A1.1, the Company applied the pre-tax cost of permanent capital of 8.76% calculated in Exhibit A-14, Schedule D1, to calculate the return on the regulatory asset balance. The use of the pre-tax cost of permanent capital is counter to the Commission previously approved use of the Company's short-term debt rate.

Although Schedule A1.1 was sponsored by Company witness Vangilder, the explanation for the change for the use of the pre-tax cost of permanent capital is provided on page 16 of Company witness Lepczyk. Mr. Lepczyk acknowledges that in Case No. U-20162, the Commission authorized the Company to use the short-term debt rate in calculating the return on deferred tree trimming surge costs charged to the regulatory asset. However, he argues that in the recent securitization case for the first portion of the deferred tree trimming surge costs, Case No. U-21015, the Commission determined that the Company had in fact financed the surge costs with permanent capital and not short-term debt. Mr. Lepczyk interprets that determination in Case No. U-21015 as a change in the Commission directive to now finance the deferred surge costs with permanent capital.

Q. DO YOU AGREE WITH THE COMPANY'S CONCLUSION THAT THE COMMISSION HAS CHANGED ITS DIRECTIVE THAT THE SHORT-TERM DEBT RATE SHOULD NO LONGER BE APPLIED TO CALCULATE THE RETURN ON TREE TRIMMING DEFERRED COSTS?

A. No. The conclusion reached by the Commission in Case No. U-21015, that the Company used permanent capital to finance the tree trimming surge costs securitized in that case, reflects the facts presented by the Company in that particular case for those specific costs. The evidence presented by the Company and other parties in Case No. 21015 clearly showed that the Company had not used short-term debt to finance those surge costs and instead used long-term debt and equity capital.

With regard to the additional costs included in Exhibit A-11, Schedule A1.1, the Company has the ability to finance those surge costs with short-term debt and make a showing in the next securitization case that it has used short-term debt to finance them during the period that those costs reside in the regulatory asset. The basic premise used by the Commission in Case U-20162 that the short-term debt rate should be used in calculating the return on the deferred balance of the regulatory asset has not changed. As the Commission stated in the order in Case No. U-20162:

> The Commission finds it appropriate to move forward with the surge proposal as the best way to balance these considerations…as a regulatory asset, with application of the short-term debt cost rate adopted in this order of 3.56% rather than the pretax permanent overall cost of capital proposed by DTE Electric. This will reduce overall costs and is expected to be temporary given the company's plans to file for securitization of the tree trimming regulatory asset [5 Tr 105].

> Thus, the Commission finds the short-term debt rate to be more appropriate than the overall cost of capital.[96]

Therefore, the use of the short-term rate is still appropriate in this rate case. The Company has the opportunity to finance the surge costs with short-term debt as expected by the Commission and match its cost of financing with the return earned on the regulatory asset balance.

Q. HAVE YOU CALCULATED THE REVISED RETURN BASED ON THE SHORT-TERM DEBT RATE?

A. Yes. In Exhibit AG-1.50, I applied the short-term debt rate of 1.74% proposed by the Company in Exhibit A-14, Schedule D1, to the regulatory asset average balance of $80,147,000 to calculate a return of $1.395,000. This amount reduces the Company's proposed return $7,021,000 by $5,626,000 and also lowers the Company's revenue deficiency by the same amount.

X. Adjustments To Revenue Deficiency

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

[96] MPSC Case No. U-20162, May 2, 2019 order at page 80.

A. Exhibit AG-1.51 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $59.8 million, which is a reduction of $328.4 million from the Company's requested level of $388.2 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $59.8 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 nearly 20 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 EXPERIENCE

During his 27-year career at SEMCO Energy, MCN Energy and MichCon, he held various analytical, accounting, managerial and executive positions. 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.

Experience and Qualifications of Sebastian Coppola

Mr. Coppola is intricately knowledgeable of capital markets and financial institutions. As Treasurer and Vice President of Finance, he has 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 has 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.

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.

As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, he has been intricately involved in operating and construction programs, gas cost recovery and reconciliation cases, gas purchase strategies and rate case filings.

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.

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 and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, Detroit Edison, MichCon (DTE Gas), Michigan Gas Utilities Corp, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company, Washington Gas, and Wisconsin Public Service Company.

- **Specific Regulatory Proceedings and Related Experience:**
    - 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.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECO) 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed rebuttal testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2020-2021 GCR plan reconciliation case No. U-20554.
- 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 Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2020-2021 GCR plan reconciliation case No. U-20552.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utility Corporation (MGUC) 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2020 PSCR plan reconciliation case No. U-20526
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (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 Company (DTE Gas) 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (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 Consumers Energy Company (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 DTE Electric Company (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 Energy Gas Company (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 DTE Electric Company (DTEE) 2018 PSCR Reconciliation in case U-20203.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.

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 Michigan Gas Utilities Corporation (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 DTE Electric (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 Energy Gas Company (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.

Experience and Qualifications of Sebastian Coppola

- 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.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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

Experience and Qualifications
of Sebastian Coppola

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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications
of Sebastian Coppola

- 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.

Corporate Analytics

Table of Schedules

Witness Coppola
Case No. U-20836

Title	Schedule
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Distribution Cap. Ex. Historical Capital Expenditures,	Exhibit AG-1.4
Distribution Cap. Exp.- Historical Strategic Capital Program	Exhibit AG-1.5
Distribution Suppliers & Material Expanded Lead Times	Exhibit AG-1.6
Distribution Underground Line Relocation Pilot Project	Exhibit AG-1.7
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Tree Trimming Surge Program Cost Savings	Exhibit AG-1.11
Accountability for SAIDI Goals Not Achieved	Exhibit AG-1.12
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Cost of Common Equity-DCF	Exhibit AG-1.29
Cost of Common Equity-CAPM	Exhibit AG-1.30
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Peer Group Analysis	Exhibit AG-1.33
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Moody’s Cash Flow Coverage Ratio	Exhibit AG-1.35
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DTEE Incentive Measures Achieved	Exhibit AG-1.49
Calculation of Return on Tree Trimming Surge Costs	Exhibit AG-1.50
Revenue Deficiency Calculation	Exhibit AG-1.51


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

Operating EPS guidance

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

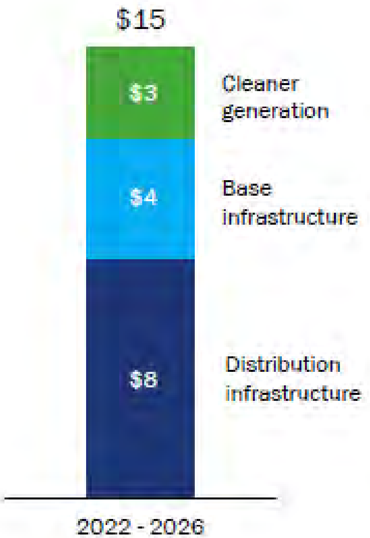
Focusing on the grid of the future and continued decarbonization efforts

- 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 Electric investment plan
(billions)



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

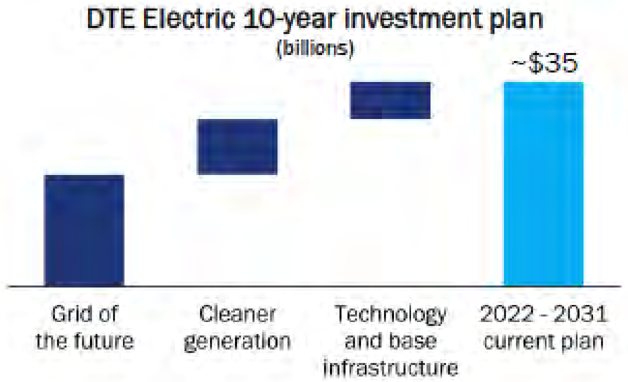
- Hardening the system with circuit rebuilds, new poles, cables and transformers
- Rebuilding sub-transmission and substations for increased capacity and reliability
- Technology and automation driving down outages and their duration

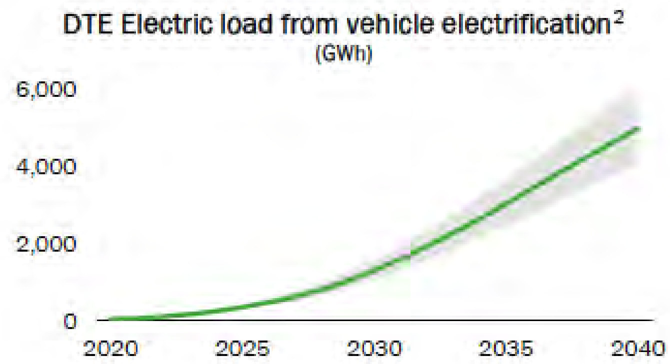
Accelerating the cessation of coal use drives replacement investment

- 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

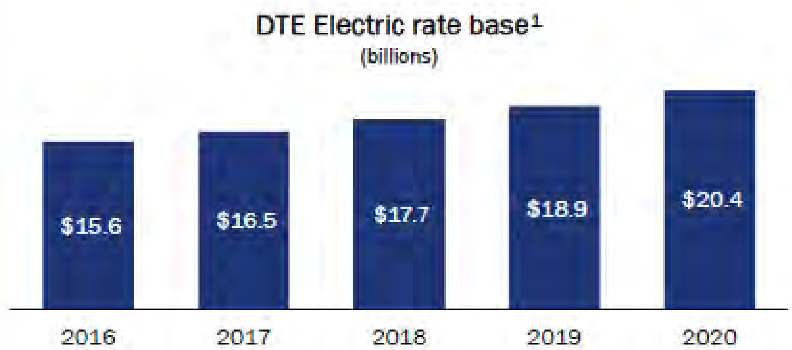


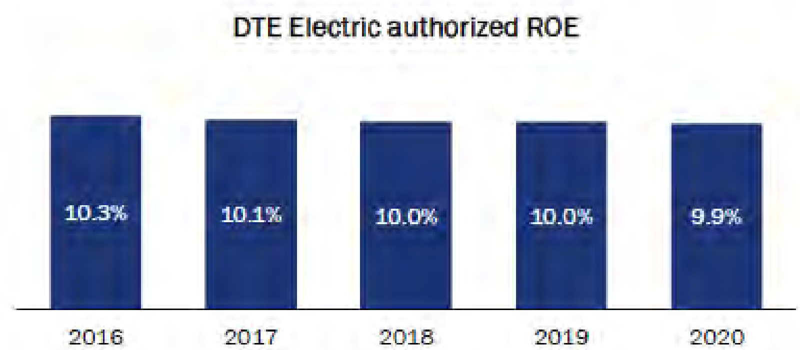


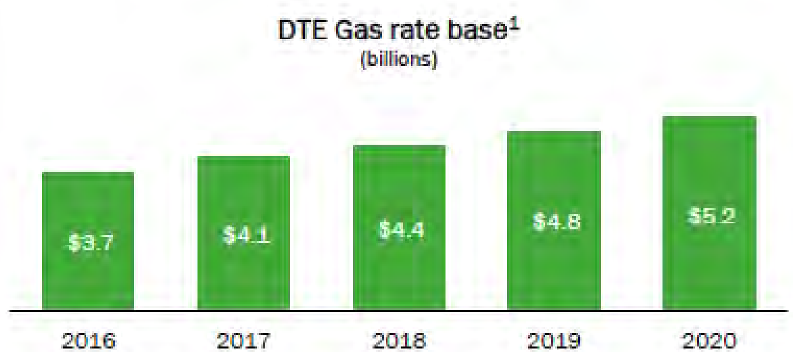
DTE

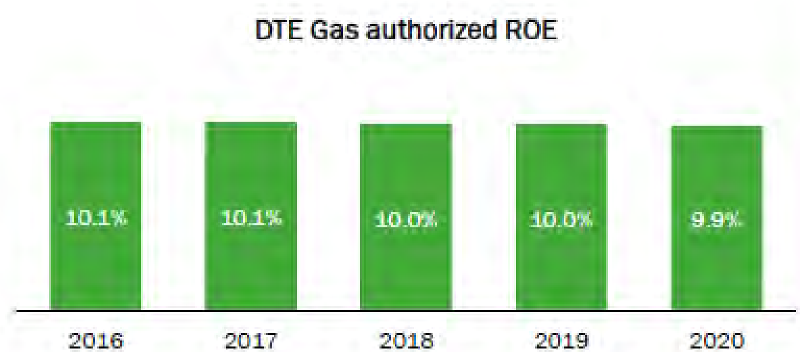
1. Examples include combined cycle plant with carbon capture and storage and hydrogen
2. Excludes underlying macroeconomic conditions including energy efficiency programs

Utilities have provided solid rate base growth









DTE

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

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-9.311b
Respondent:	T. Uzenski
	1 of 1

Question: Refer to Exhibit A-12, Schedule B5, pertaining to Capital Expenditures. Please:

b. Provide the amount of Contingency Costs included in each of the line items for the projected periods.

Answer: The only line on Exhibit A-12, Schedule B5 with contingency is line 10, Information Technology. Please see responses to STDE-12.6a, b, c.

Attachment: *None*

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-12.6c
Respondent:	A. Pizzuti
	1 of 1

Question: Please identify all contingency or reserve expenditures that were included in the bridge period or test years in the Company's filing. For each instance of a contingency or reserve expenditure included in the filing, please provide:

c. the timing of the contingency;

Answer: Contingency in the amount of $2.1 million for 10 months ending 10/31/2022 (May-October 2022 timing) and $2.1 million for 12 months ending 10/31/2023 (November 2022-May 2023 timing) was included for the Time of Use project.

Attachment: None.

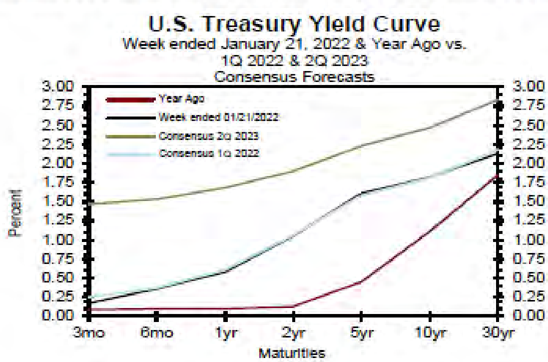
CPI 2022 and 2023 Blue Chip Financial Forecast

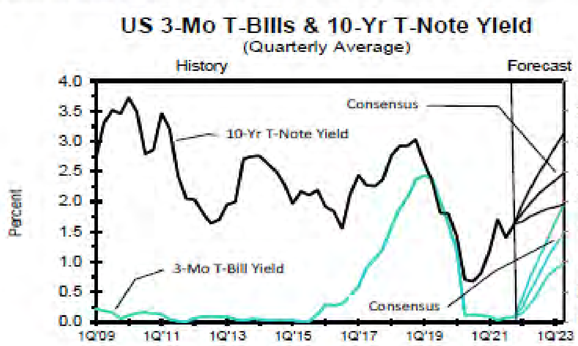
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

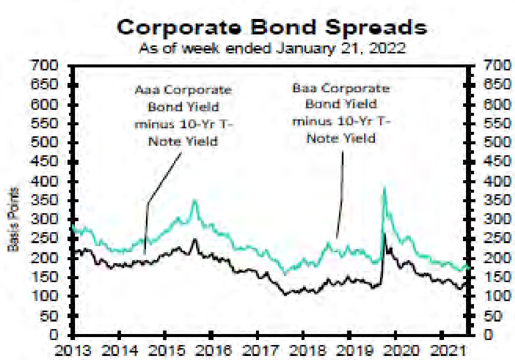
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*						
Interest Rates	Jan 21	Jan 14	Jan 7	Dec 31	Dec	Nov	Oct	4Q 2021	1Q 2022	2Q 2022	3Q 2022	4Q 2022	1Q 2023	2Q 2023
Federal Funds Rate	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.2	0.5	0.8	1.0	1.3	1.5
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.3	3.6	3.9	4.1	4.3	4.5
SOFR	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.2	0.4	0.7	0.9	1.2	1.4
Commercial Paper, 1-mo.	0.07	0.07	0.07	0.06	0.07	0.06	0.05	0.06	0.2	0.5	0.7	1.0	1.2	1.4
Treasury bill, 3-mo.	0.17	0.12	0.09	0.06	0.06	0.05	0.05	0.05	0.3	0.5	0.8	1.1	1.3	1.5
Treasury bill, 6-mo.	0.36	0.28	0.23	0.20	0.15	0.07	0.06	0.09	0.4	0.6	0.9	1.1	1.3	1.5
Treasury bill, 1 yr.	0.58	0.48	0.41	0.37	0.30	0.18	0.11	0.20	0.6	0.9	1.1	1.3	1.5	1.7
Treasury note, 2 yr.	1.05	0.93	0.83	0.74	0.68	0.51	0.39	0.53	1.1	1.3	1.4	1.6	1.8	1.9
Treasury note, 5 yr.	1.61	1.51	1.43	1.27	1.23	1.20	1.11	1.18	1.6	1.7	1.9	2.0	2.1	2.2
Treasury note, 10 yr.	1.82	1.75	1.70	1.51	1.47	1.56	1.58	1.54	1.8	2.0	2.1	2.2	2.4	2.5
Treasury note, 30 yr.	2.13	2.09	2.07	1.91	1.85	1.94	2.06	1.95	2.2	2.3	2.5	2.6	2.7	2.8
Corporate Aaa bond	3.08	3.01	2.97	2.83	2.79	2.79	2.85	2.81	3.0	3.2	3.4	3.6	3.7	3.9
Corporate Baa bond	3.58	3.49	3.45	3.30	3.26	3.25	3.31	3.27	3.7	3.9	4.2	4.4	4.5	4.7
State & Local bonds	2.74	2.70	2.61	2.57	2.57	2.57	2.59	2.58	2.6	2.8	2.9	3.1	3.2	3.4
Home mortgage rate	3.56	3.45	3.22	3.11	3.10	3.07	3.07	3.08	3.5	3.7	3.9	4.0	4.1	4.3

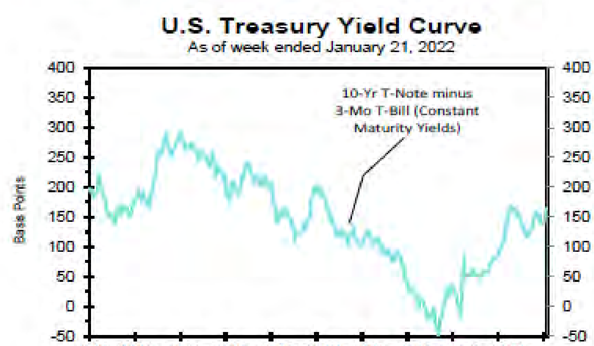
	History								Consensus Forecasts-Quarterly					
Key Assumptions	1Q 2020	2Q 2020	3Q 2020	4Q 2020	1Q 2021	2Q 2021	3Q 2021	4Q 2021	1Q 2022	2Q 2022	3Q 2022	4Q 2022	1Q 2023	2Q 2023
Fed's AFE $ Index	111.3	112.4	107.2	105.1	103.4	102.9	105.0	107.0	108.0	108.2	108.3	107.9	107.6	107.3
Real GDP	-5.1	-31.2	33.8	4.5	6.3	6.7	2.3	6.9	2.2	4.0	3.2	2.6	2.5	2.3
GDP Price Index	1.6	-1.5	3.6	2.2	4.3	6.1	6.0	6.9	4.3	3.4	3.0	2.8	2.6	2.5
Consumer Price Index	1.0	-3.1	4.7	2.4	3.7	8.4	6.6	8.2	4.4	3.4	2.8	2.7	2.5	2.5
PCE Price Index	1.3	-1.6	3.7	1.5	3.8	6.5	5.3	6.5	4.0	3.1	2.7	2.5	2.4	2.4

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 Advanced Foreign Economies 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-20836
Requestor:	AG
Question No.:	AGDE-6.192a
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.4, page 4. Please provide the following information in Excel:

a. Expand this schedule to add actual amount for each year 2016 to 2021.

Answer: The Company does not have information in this format for 2016.

See attachment U-20836 AGDE-6.192a-01 Capital Exhibit A-12 B5.4 Pg 4.

Attachment: U-20836 AGDE-6.192a-01 Capital Exhibit A-12 B5.4 Pg 4

U-20836 AGDE-6.192a-01 Capital Exhibit A-12 B5.4 pg 4

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
Page: 4 of 12

	(a)						(b)	(c)	(d)	(e)	(f)	(g)
			Capital Expenditures									
			Historical	Historical	Historical	Historical	Historical	Projected Calendar Year			Bridge Period	Test Year
Line No.	Description		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 12/31/2021	12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	22 mos. ending 10/31/2022	12 mos. ended 10/31/2023
1	**Connections and New Load**											
2	Small Load Growth Projects (Blanket)		8,977	12,613	15,856	18,053	21,661	19,872	19,152	19,707	35,832	19,615
3	Customer Connections		71,143	84,777	91,418	89,211	108,810	113,632	117,342	120,745	211,418	120,178
4	Customer Connections CIAC		(16,628)	(14,161)	(12,746)	(14,756)	(15,524)	(18,796)	(19,410)	(19,972)	(34,971)	(19,879)
5	Customer Connections (Net of CIAC)		54,516	70,616	78,672	74,455	93,286	94,836	97,933	100,773	176,447	100,300
6	New Business Projects	1/	52,363	37,842	35,231	29,957	50,761	54,031	31,781	32,703	80,515	32,549
7	New Business Projects CIAC		(10,486)	(12,814)	(8,849)	(4,709)	(9,390)	(8,494)	(4,996)	(5,141)	(12,657)	(5,117)
8	Subtotal New Business Projects (net of CIAC)		41,877	25,028	26,382	25,248	41,371	45,537	26,785	27,562	67,858	27,433
9	**Total Connections and New Load**		**132,483**	**135,232**	**142,504**	**137,221**	**181,232**	**187,535**	**168,276**	**173,156**	**327,765**	**172,342**
10	**Total Connections and New Load CIAC**		(27,113)	(26,975)	(21,594)	(19,466)	(24,914)	(27,290)	(24,406)	(25,113)	(47,628)	(24,995)
11	**Total Connections and New Load (Net of CIAC)**		105,369	108,257	120,910	117,755	156,318	160,246	143,870	148,042	280,138	147,347
12	**Relocations**											
13	Small Relocation Projects (Blanket)		7,004	7,607	8,316	14,943	7,018	7,208	15,853	16,313	20,419	16,236
14	Major Infrastructure Relocation Project											
15	Gordie Howe International Bridge		6,673	10,915	5,351	(874)	489	3,161	700	-	3,993	166
16	Relocation Projects (excl.Major Infrastructure Projects)	2/	2,698	7,661	3,662	10,059	20,146	21,548	10,671	10,981	30,441	10,929
17	Relocation Projects CIAC		(1,359)	(3,648)	-	(1,930)	131	(4,134)	(2,047)	(2,107)	(5,840)	(2,097)
18	Subtotal Relocation Projects (Net of CIAC)		1,339	4,013	3,662	8,129	20,277	17,414	8,624	8,874	24,601	8,833
19	**Total Relocations**		**16,375**	**26,183**	**17,328**	**24,128**	**27,653**	**31,917**	**25,178**	**27,294**	**54,853**	**27,332**
20	**Total Relocations CIAC**		(1,359)	(3,648)	-	(1,930)	131	(4,134)	(2,047)	(2,107)	(5,840)	(2,097)
21	**Total Relocations (Net of CIAC)**		15,016	22,535	17,328	22,199	27,783	27,783	23,130	25,187	49,013	25,235
22	**Electric System Equipment**											
23	Distribution Transformers & Regulators		22,719	25,827	27,693	17,856	3,076	151	-	-	151	-
24	Major Equipment		14,531	14,945	11,759	21,435	13,594	12,550	22,740	23,400	31,500	23,290
25	Meters		7,980	11,196	10,801	16,891	13,800	12,949	17,920	18,439	27,882	18,353
26	**Total Electric System Equipment**		**45,230**	**51,967**	**50,253**	**56,182**	**30,471**	**25,650**	**40,660**	**41,839**	**59,533**	**41,642**

1/ Exhibit A-12, Schedule B5.4 - page 6, line 59
2/ Exhibit A-12, Schedule B5.4 - page 7, line 30

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-6.193a
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.4, page 5. Please provide the following information in Excel:

a. Expand this schedule to add actual amounts for each year 2016 to 2021.

Answer: The Company does not have 2016 data in this format.

See attachment U-20836 AGDE-6.193a-01 Capital Exhibit A-12 B5.4 Pg 5.

Attachment: U-20836 AGDE-6.193a-01 Capital Exhibit A-12 B5.4 Pg 5

U-20836 AGDE-6.193a-01 Exhibit A-12 B5.4 Pg 5

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
Page: 5 of 12

	(a)				(b)		(c)	(d)	(e)	(f)	(g)
							Capital Expenditures				
		Historical	Historical	Historical	Historical	Historical	Projected Calendar Year			Bridge Period	Test Year
Line No.	Description	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 12/31/2021	12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	22 mos. ending 10/31/2022	12 mos. ended 10/31/2023
27	**NRUC and Improvement Blankets**										
28	System Improvements	6,327	8,887	10,166	12,117	9,715	8,607	14,527	14,949	20,713	14,878
29	Normal Retirement Unit Changeouts (NRUC)	5,090	3,782	7,220	7,398	5,702	5,319	7,849	8,076	11,859	8,038
30	Operational Technologies	2,680	2,955	2,800	5,401	5,535	5,546	5,730	5,897	10,322	5,869
31	Batteries and Chargers	1,654	2,221	1,400	2,058	1,918	2,628	2,183	2,246	4,447	2,236
32	Animal Mitigation	26	35	4	194	35	35	206	212	206	211
33	**Total NRUC and Improvement Blankets**	**15,778**	**17,879**	**21,589**	**27,168**	**22,905**	**22,135**	**30,495**	**31,379**	**47,547**	**31,232**
34	**General Plant, Tools & Equipment and Miscellaneous**										
35	Substation Physical Security	-	-	704	562	1,753	1,644	2,000	-	3,310	333
36	Warren SC Transformer Yard Reorganizaton	-	-	-	-	-	-	1,873	384	1,561	632
37	General Plant, Tools & Equipment and Miscellaneous	4,020	5,887	4,815	8,007	5,692	7,387	8,494	8,741	14,466	8,700
38	**Total General Plant, Tools & Equipment and Miscellaneous**	**4,020**	**5,887**	**5,519**	**8,569**	**7,445**	**9,031**	**12,367**	**9,125**	**19,337**	**9,665**
39	**Public Lighting Department Project**	-	-	-	21,051	19,353	21,282	7,700	-	28,982	-
40	**Total Customer Connections, Relocations & Other**	213,886	237,147	237,193	274,320	289,059	297,550	287,021	282,793	538,017	282,214
41	**Total Cust Connections, Relocations & Other CIAC**	(28,472)	(30,623)	(21,594)	(21,395)	(24,783)	(31,423)	(26,453)	(27,220)	(53,468)	(27,092)
42	**Total Cust Connections, Relocations & Other Net of CIAC**	185,414	206,525	215,599	252,924	264,275	266,126	260,568	255,572	484,549	255,122

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-6.191
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.4, page 1. Please expand this schedule to add actual amounts for each year 2016 to 2021 and provide in Excel.

Answer: The Company does not have information in this format for 2016.

See attachment U-20836 AGDE-6.191-01 Capital Exhibit A-12 Schedule B5.4 Pg 1.

Attachment: U-20836 AGDE-6.191-01 Capital Exhibit A-12 Schedule B5.4 Pg 1

U-20836 AGDE-6.191-01 Capital Exhibit A-12 B5.4 Pg 1

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
M. Elliott-Andahazy 6/
P. Smith 7/
Page: 1 of 12

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
M. Elliott-Andahazy
P. Smith 7/
Page: 2 of 12

	(a)						(b)	(c)	(d)	(e)	(f)	(b)	(c)	(d)	(e)	(f)	(g)
			Capital Expenditures									Capital Expenditures					
			Historical	Historical	Historical	Historical	Historical	Projected Bridge Period			Projected Test Year	Historical	Normalization	Adjusted	Projected Calendar Year		
Line			12 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	12 mos. ended	10 mos. ending	22 mos. ending	12 mos. ended	12 mos. ended	Adjustment	Historical	12 mos. ended	12 mos. ended	12 mos. ended
No.	Description		12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2021	10/31/2022	10/31/2022	10/31/2023	12/31/2020	9/	Test Period sum (b) thru (c)	12/31/2021	12/31/2022	12/31/2023
1	**Base Capital Programs**																
2	Emergent Replacements																
3	Storm	1/	122,588	142,108	178,931	150,897	395,286	380,618	141,803	522,421	174,276	150,897	9,499	160,396	380,618	170,164	175,098
4	Non - Storm	1/	126,187	159,555	163,112	155,324	209,236	190,816	143,721	334,537	176,634	155,324	7,242	162,566	190,816	172,466	177,467
5	Substation Reactive	1/	35,495	44,275	40,386	38,131	46,008	40,621	36,954	77,575	45,417	38,131	3,668	41,799	40,621	44,345	45,631
6	Emergent Replacement Reduction Based on Strategic Spend		-	-	-	-	-	-	(12,684)	(12,684)	(24,615)	-	-	-	-	(15,221)	(26,494)
7	Subtotal Emergent Replacements		284,270	345,938	382,429	344,352	650,531	612,055	309,794	921,849	371,711	344,352	20,408	364,761	612,055	371,753	371,702
8	Customer Connections, Relocations & Other																
9	Connections and New Load	2/	132,483	135,232	142,504	137,221	181,232	187,535	140,230	327,765	172,342	137,221			187,535	168,276	173,156
10	Relocations	2/	16,375	26,183	17,328	24,128	27,653	31,917	22,936	54,853	27,332	24,128			31,917	27,523	27,294
11	Electric System Equipment	2/	45,230	51,967	50,253	56,182	30,471	25,650	33,883	59,533	41,642	56,182			25,650	40,660	41,839
12	NRUC and Improvement Blankets	2/	15,778	17,879	21,589	27,168	22,905	22,135	25,412	47,547	31,232	27,168			22,135	30,495	31,379
13	General Plant, Tools & Equipment and Miscellaneous	2/	4,020	5,887	5,519	8,569	7,445	9,031	10,306	19,337	9,665	8,569			9,031	12,367	9,125
14	Public Lighting Department Project	2/	-	-	-	21,051	19,353	21,282	7,700	28,982	-	21,051			21,282	7,700	-
15	Subtotal Customer Connections, Relocations & Other		213,886	237,147	237,193	274,320	289,059	297,550	240,467	538,017	282,214	274,320			297,550	287,021	282,793
16	Customer Advances for Construction	2/	(28,472)	(30,623)	(21,594)	(21,395)	(24,783)	(31,423)	(22,044)	(53,468)	(27,092)	(21,395)			(31,423)	(26,453)	(27,220)
17	**Total Base Capital Programs**		**469,683**	**552,463**	**598,028**	**597,277**	**914,806**	**878,181**	**528,217**	**1,406,399**	**626,833**	**597,277**			**878,181**	**632,321**	**627,275**
18	**Strategic Capital Programs**																
19	Infrastructure Resilience and Hardening	3/	119,448	171,761	158,978	167,035	187,432	189,706	265,694	455,400	346,091	167,035			189,706	318,833	351,543
20	Infrastructure Redesign and Modernization	4/	42,844	69,393	61,958	49,311	94,857	92,399	215,146	307,545	314,334	49,311			92,399	258,176	325,566
21	Technology and Automation	5/ 6/ 7/	19,397	38,803	92,327	91,293	76,633	73,421	99,551	172,972	137,342	91,293			73,421	119,461	140,918
22	**Subtotal Strategic Capital Programs**		**181,689**	**279,957**	**313,263**	**307,640**	**358,922**	**355,525**	**580,391**	**935,917**	**797,767**	**307,640**			**355,525**	**696,469**	**818,027**
23	**Total Capital**		**651,372**	**832,419**	**911,292**	**904,916**	**1,273,728**	**1,233,707**	**1,108,609**	**2,342,315**	**1,424,600**	**904,916**			**1,233,707**	**1,328,790**	**1,445,302**
24	**Regulatory Asset**																
25	Advanced Distribution Management System (ADMS)	8/	**-**	**-**	**2,817**	**3,989**	**2,693**	**2,837**	**6,405**	**9,242**	**2,978**	**3,989**		**3,989**	**2,837**	**8,409**	**974**

1/ Exhibit A-12, Schedule B5.4 - page 3
2/ Exhibit A-12, Schedule B5.4 - pages 4-5, lines 10, 20, , , , & 42
3/ Exhibit A-12, Schedule B5.4 - page 8, line
4/ Exhibit A-12, Schedule B5.4 - page 10, line
5/ Exhibit A-12, Schedule B5.4 - page 11, line

6/ ADMS/SOC projects sponsored by Company Witness M. Elliott-Andahazy
7/ AMI projects sponsored by Company Witness P. Smith
8/ Regulatory Asset treatment per Case No. U-20162

6/ ADMS/SOC projects sponsored by Company Witness M. Elliott-Andahazy
7/ AMI projects sponsored by Company Witness P. Smith
8/ Regulatory Asset treatment per Case No. U-20162
9/ Normalization Adjustment:
Emergent Replacements (Exh. B5.4, p.3, Line 25, col.

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-1.79
Respondent:	S. Pfeuffer
Page:	1 of 2

Question: Please describe all known material delivery supply/procurement issues the Company is aware of. The response should include the type of equipment, projected delay period, and the projected duration of the issue.

Answer: DTE Electric objects to the request for the reason that the request is vague, unclear and incapable of answer in its current form as it is uncertain what is meant by "all known material delivery supply/procurement issues", as this could be interpreted in several different ways, and also because there is no date range or level of detail specified. Subject to these objections, but without waiving them, DTE Electric's response follows:

In Distribution Operations, since the beginning of Q4 2021, the majority of construction materials used for new business, maintenance, strategic, and emergent work have had lead times increase, causing supply chain difficulties that for some projects have delayed the Company's work. These delays are expected to continue through the end of Q2 2023, and possibly longer. These lead time increases are caused by several factors including but not limited to the following:

- Raw material availability
- Weather impacts causing utilities across the country to increase their material usage for emergent work
- Manufacturers' capacity constraints unable to keep up with increased demand across their portfolios
- Transportation issues

The most critical categories of material that the Company's supply chain team is monitoring on a weekly basis are:

- Transformers (previous lead time was 3 months, now12+ months)
- Wire and cable (previous lead time was 3 months, now 6 months)
- Pole top maintenance hardware (previous lead time was 3 weeks, now 12 weeks)
- Conduit (previous lead time was 4 weeks, now 14 weeks)

Co-respondent(s): Legal

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-1.79
Respondent:	S. Pfeuffer
Page:	1 of 2

- Meters (previous lead time was 4 weeks, now 20 weeks)

The DTEE DO Construction and Supply Chain Management teams are working together to mitigate impacts of the material delivery supply/procurement issues. These mitigation actions include:

1.) Increasing the number of suppliers for transformers, insulators and cross arms.
2.) Demand planning with a longer time horizon, including securing product slots for next year and beyond with suppliers.
3.) Deploying weekly and daily tracking calls with key suppliers including weekends. This helps drive collaboration and leverage our resources including transportation in order to keep orders on track.
4.) Sending Supply Chain and other employees to supplier facilities to provide real time governance on our materials.

Attachments: N/A

Co-respondent(s): Legal

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-6.189a
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to page 115 of Ms. Pfeuffer's direct testimony. Please:

a. Explain why only half of the customers have been transferred to the underground loop.

Answer: As stated on page 115 and starting on line 4 of my testimony, there have been two major challenges we have had to address in this project: addressing debris and acquiring the required customer approvals. Acquiring customer approvals was the most significant challenge for transferring customers to the underground. To date, 36 of the 61 customers have been connected. The challenge of aquiring customer approvals from the home owner still exists with the remaining homes.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-6.189c
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to page 115 of Ms. Pfeuffer's direct testimony. Please:
c. Provide the Company's assessment of undergrounding overhead lines based on the pilot projects completed to date.

Answer: The question refers to page SGP-115, which describes the Appoline pilot. As stated on that page the two major challenges with the Appoline pilot have been addressing debris and acquiring customer approvals. Addressing these challenges is described on page SGP-116 "… the Company has engaged in benchmarking efforts to learn from other utilities that have implemented similar efforts. With the lessons learned from the Appoline pilot and benchmarking work, further pilots are being planned to improve customer engagement approaches, implement more cost-effective methods, and enhance processes with the purpose of scaling up Strategic Undergrounding in areas where it is needed."

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-6.189d
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to page 115 of Ms. Pfeuffer's direct testimony. Please:

d. Explain what else is there to better understand about strategic undergrounding by meeting with communities.

Answer: The question refers to page SGP-115, which describes the Appoline pilot. As stated on that referenced page, the two major challenges with the Appoline pilot have been addressing debris and acquiring customer approvals. The goal for the community engagement aspects of future pilots are to develop processes that improve customers' acceptance of the equipment placement including the junction box needed on the back of their homes and padmounted transformers in their front lots. The community engagement plan is described in subsection 5 of Exhibit A-12, Schedule B5.4.2, DTE will develop a project specific stakeholder engagement plan. This engagement plan will include identifying key stakeholders including customers and community leaders, essential engagement activities, methods, and cadence of communication to stakeholders, and monitoring stakeholder feedback.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-6.190
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to page 116, lines 1-11 of Ms. Pfeuffer's direct testimony. Please explain why more pilot projects are necessary. What else do you expect to learn that you do not know already from the existing pilot projects? What will you be doing differently in the other pilots?

Answer: As stated on page SGP-116, customers served by underground infrastructure have 34% to 52% better All Weather SAIDI than customers served by overhead, and this presents an opportunity to improve the Company's customers' reliability. However, there are other factors, such as cost and customer acceptance that have to be considered when deciding to implement Strategic Undergrounding. The Company's Appoline pilot demonstrated the reality of these challenges and the Company's benchmarking work has identified some practices that can address these challenges. These potential solutions and other aspects of undergrounding will be tested during the pilots, including those listed on page SGP-117 : – reduction in down wires, accesibility of overhead equipment, cost to maintain underground circuits over time, coordination with other infrastructure projects, community support, and others. See the response to ADGE-6.189c and d and Exhibit A-12, Schedule B5.4.2 for additional aspects on the Company's plans for Strategic Undergrounding.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-18.3a
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to Ms. Pfeuffer's direct testimony, page SGP-116, lines 8-11, where she states that further pilots are being planned.

a. Please list these additional pilots.

Answer: Additional pilots include the Fairmount DC1593 Strategic URD Undergrounding project and the Strategic Service Undergrounding Program

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-18.3biv
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to Ms. Pfeuffer's direct testimony, page SGP-116, lines 8-11, where she states that further pilots are being planned.

b. For each pilot listed in part (a), please provide:

iv. The pilot's projected capital expenditures for January 1, 2022 – October 31, 2022.

Answer: Fairmount DC1593: $4.0M
Strategic Service Undergrounding Program: $11.1M

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-18.3bv
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to Ms. Pfeuffer's direct testimony, page SGP-116, lines 8-11, where she states that further pilots are being planned.

b. For each pilot listed in part (a), please provide:

v. The pilot's projected capital expenditures for November 1, 2022 – October 31, 2023.

Answer: Fairmount DC1593: $12.7M
Strategic Service Undergrounding Program: $24.1M

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.201
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 6, lines 20-23 of Mr. Andahazy's direct testimony. Please provide the total estimated cost of the ADMS project from inception to completion by year as of the time it was presented in Case No. U-20162. Provide this same total cost by sub-system or component system (GMS, EMS, OMS, etc.) by year along with each phase of the project with related cost for each phase, and the timeline for each phase at that point in time.

Answer: Throughout these responses, the Company will be referring to Ms. Morgan Elliott Andahazy's testimony.

The table below displays the total estimated investment planned from inception to completion as of the time the projects were presented in MPSC Case No U-20162, part III filing and Exhibit A12, schedule B5.4, page 9. These amounts are broken down by component at the project level (GMS/EMS, DMS/OMS, NMS) and calendar year. In addition, the ADMS: GMS/EMS and NMS are fully implemented, while the ADMS: DMS/OMS project is currently in development and testing. The Company does not have the investment total for ADMS: GMS/EMS, ADMS: DMS/OMS, or ADMS: NMS broken down by phase, which in the context of the ADMS project means, design, development, testing, or implementation.

Capital ($ millions) projected as of MPSC Case No U-20162

ADMS Component	2017	2018	2019	2020	2021	Total
GMS/EMS	1.0	21.9	6.5			29.4
DMS/OMS	1.4	2.5	25.4	27.9	10.2	67.4
NMS		4.7	11.4	2.6		18.8

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.204a
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 12, lines 20-25, and page 13, lines 1-7, of Mr. Andahazy's direct testimony.

Please:

a. Identify the type of system data to which you are referring. What is this data used for?

Answer: The type of system data MEA-12, lines 20-25 is referring to is the electrical and physical characteristics of the distribution grid. The data is used to plan and operate the electrical grid through both human and computer programs employing various sets of the data.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.204b
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 12, lines 20-25, and page 13, lines 1-7, of Mr. Andahazy's direct testimony.

Please:

b. What was done before NMS with the system data and why was it not of high quality?

Answer: Prior to NMS being launched, DTEE had the necessary electrical and physical characteristic data to support the Company's objectives and processes at the time. The processes allowed for manual identification and correction of data within the planning and operational spaces; however, the changing demands for automation through computer systems necessitated a higher quality data set than previously needed.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.204c
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 12, lines 20-25, and page 13, lines 1-7, of Mr. Andahazy's direct testimony.

Please:

c. What will the $6.3 million be spent on? Provide also a reference on which page and line number of Exhibit A-12, Schedule B5.4 this amount is included.

Answer: The $6.3 million will be spent on the items described in MEA-13, lines 11-24. This investment can be found in Exhibit A-12, Schedule B5.4, page 11, line 3 ADMS: Network Management System

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.204d
Respondent:	M. Elliott Andahazy
	1 of 1

Question: 204. Refer to page 12, lines 20-25, and page 13, lines 1-7, of Mr. Andahazy's direct testimony.

Please:

d. What further development of high-quality data is necessary and why?

Answer: The further development of high-quality data and its necessity can be found in MEA-14, lines 7-23.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.204e
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 12, lines 20-25, and page 13, lines 1-7, of Mr. Andahazy's direct testimony.

Please:

e. Why was this further development of high-quality data not included in the original scope of the NMS project?

Answer: The original scope of the NMS project focused on initial elements needed for the ADMS project as understood at the time of inception. Through DTE's grid modernization process, wherein the Company anticipated and planned for customers' furture demands and requirements, the Company identified the need for additional electrical grid data elements and data model connectivity (reference STDE-4.10 for examples). These additional features that were identified were beyond the original NMS scope. The deliberate separation into a further phase of the NMS was to ensure that high-quality data and new data models needed to support more planning needs for grid modernization are addressed as needed when downstream processes and computer programs can employ them.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.205a
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 13, lines 9-24 of Mr. Andahazy's direct testimony. Please:

a. This section of your testimony is difficult to understand and it looks like you are trying to explain different concepts, but in a confusing manner. Please provide a more direct and clear explanation of this section.

Answer: DTE Electric objects to the request for the reason that it is argumentative and excessively vague. It is excessively vague because it is unknown what might be considered "more direct and clear" to the AG, especially as page 13, lines 9-24 appear direct and clear to the witness. In further answer and without waiving the objection, the Company would state as follows:

One aspect of DTEE's grid modernization process is to anticipate and plan for customer demands and their changing grid needs in the future. While conducting this process, the Company identified the need for additional electrical grid data elements and data model connectivity beyond the original NMS scope. With this growing number of data elements and data models identified, the Company had two choices, either increase the amount of FTEs to a level sufficient to manually maintain all elements of the data model in perpetuity (see response STDE-4.4d), or the Company could automate that data maintenance. The best option was to automate data maintenance and introduce quality controls on the new data elements and data models. To do this, the additional phase of the NMS investment is needed.

Attachment: N/A

Co-Respondent(s): Legal

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.205b
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 13, lines 9-24 of Mr. Andahazy's direct testimony. Please:
b. Are you proposing to develop new features or functionalities instead of getting better data into the system? Why are these new functionalities critically necessary?

Answer: DTEE is proposing to accomplish both including better data into the system and adding new features and functionality to the system's tools. As restated in AGDE-7.205a, additional data that was not previously captured in the Company's systems is needed to support the changing needs of distribution planning processes to meet our customers' demands and the requirements of a more interconnected grid. Additionally, new functionality to detect, correct, and ensure sustained data quality and consistency on these new data elements is necessary in order to meet the daily network model refresh requirements of modern grid planning and operations computer systems.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.205c
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 13, lines 9-24 of Mr. Andahazy's direct testimony. Please:
c. Will the financial benefits from the added functions exceed the $6.3 million in capital expenditures? If yes, when will they start? Provide a copy of the cost/benefit analysis in Excel with formulas intact.

Answer: The Company has not calculated the direct financial benefits from this NMS project, however there is expected to be cost avoidance associated with this project. Please reference responses in STDE-4.4d and STDE-4.11a.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.207
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 17, lines 20-25 of Mr. Andahazy's direct testimony. Please provide the current cost estimate to complete and implement the OMS and DMS sub-systems individually from inception to completion by year. Provide the most current timeline for development and implementation with each remaining phase and cost to be incurred in each phase. Identify the phase that the project is currently in.

Answer: The table below displays the total investment (actual thru 2021 and estimate in 2022/2023) for the ADMS: DMS/OMS project (which includes the investments in ClickSoft and the Reporting project). The investment in the DMS and OMS components specifically, cannot be separated by product component as the project is supported by one common team of employees and the Company does not have separate line items for all charges to each component.

Capital ($ millions)

	2017	2018	2019	2020	2021	2022	2023	Total
ADMS:DMS/OMS	1.4	0.8	9.8	19.5	17.9	22.4	6.5	78.3
ClickSoft						6.9		6.9
Reporting				2.3	2.1	2.2		6.6
Total	1.4	0.8	9.8	21.8	20.0	31.5	6.5	91.8

As stated on MEA-25, lines 20-25, the EMS upgrade, OMS and DMS (with the exception of DMS Switch Order Management) are planned for implementation in Q4 2022. The Company will continue to partner with the ADMS: DMS/OMS vendor, OSI Inc (OSI) on the planned implementation date for the Compass mobile tool as the agreed upon functionality is delivered. As stated on MEA-26, lines 1-7, the DMS Switch Order Management tool is planned to roll-out to front-line employees in mid-2023. All of these systems can be considered in development and testing, however as referenced in response to AGDE-7.201, the Company does not have this investment broken down by phases.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.213b
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 28, lines 1-18 of Mr. Andahazy's direct testimony. Please:

b. Provide the amount of the $13.6 million that you attribute to Covid-19 delays. Provide the components of that amount and show how you arrived at those component amounts in Excel with formulas intact.

Answer: As stated in MEA-17, lines 21-25, and MEA-18, lines 1-19, there were two main reasons the ADMS: DMS/OMS project implementation date was delayed: the complexity of the technology required to support the needed mobile functionality, and the impacts imposed by the COVID restrictions. These two causes are intertwined and cannot be separated.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.214a
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to page 35, lines 1-14 of Mr. Andahazy's direct testimony. Please:

a. Provide the amount that you attribute to Covid-19 delays. Provide the components of that amount and show how you arrived at those component amounts in Excel with formulas intact.

Answer: For the cost breakdown, please see attachment U-20836 AGDE-7.214a-01 ESOC COVID Delay Impacts.

Attachment: U-20836 AGDE-7.214a-01 ESOC COVID Delay Impacts

U-20836 AGDE-7.214a-01 ESOC COVID Delay Impacts		
ESOC COVID-19 Delay - Financial Impact		
$ 617,500	Construction impact	
$ 305,000	Engineering impact	
$ 922,500	**Total ESOC COVID-19 delay impact**	

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.215c
Respondent:	M. Elliott Andahazy
	1 of 1

Question: 215. Refer to page 35, lines 16-25 of Mr. Andahazy's direct testimony. Please:

c. Provide a comparison of the components of the cost of the project now versus when it was first proposed. Explain the reason for any cost increase in each of the components of 5% or greater from the original estimate with the amount related to each reason.

Answer: ($ millions)

	Original Estimate	Actual	Delta	Reason for Change
Engineering	6.5	7.6	1.4	Added owner's engineer for onsite construction support
Construction/ refined scope	61	72.4	11.1	General contractor bid higher than budgeted – increased square footage, third party testing, additional permitting, control room equipment installation SMEs
IT Investment	4.7	8.4	3.7	Parallel operations, data center add-on, video wall software integration
Other (AFUDC, A&G, Overheads)	5.8	10.1	4.3	Due to delays
	78.0	98.5	20.5	See U-20836, MEA-36 and MEA-37

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.218
Respondent:	M. Elliott Andahazy
	1 of 1

Question: Refer to pages 41 to 44 of Mr. Andahazy's direct testimony with regard to the ASOC. Please provide the total cost of the project from inception to completion by year as it is currently forecasted and also as originally proposed. Provide the original and current timeline by phase and identify the phase that the project is currently in.

Answer: For the total cost of the project when first reported in rate case, please see the response to AGDE-7.215a.

The current forecast for ASOC is $10.2 million in 2022, $23.8 million in 2023, and $0.5 million in 2024 totaling $34.5 million. The project was competitively bid in January 2022. Design will begin in May 2022 with construction commencing Q4 2022 and completion in Q1 2024.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-4.37
Respondent:	M. Elliott Andahazy
Page:	1 of 1

Question: On MEA-34, the Company notes that half of the Operational Engineering employees are now working in the new ESOC. Please describe when DTE Electric staff moved into the new ESOC (month and year), and where the remaining half of the Operational Engineering employees are working currently and for how long they will remain working elsewhere.

Answer: As of August 2021, all personnel from Central Dispatch have been working in the ESOC control room.

As of November 2021, approximately half of the Operational Engineering employees have been working in the ESOC. The other half have been working remotely due to COVID-19 pandemic restrictions.

As of November 2021, approximately half of the SCADA Realtime Support employees have been working in the ESOC. The other half have been working remotely due to COVID-19 pandemic restrictions. As of February 10th, 100% of the SCADA Realtime Support employees have been working a hybrid model between the ESOC and remote.

As of February 18th, 2022, all control room system operators have been working in the ESOC control room.

Tentatively scheduled for May 2022, DTE is transitioning most of its personnel not included in the control room operations to a hybrid model as the pandemic subsides. This full transition will include the remainder of the Operational Engineering group and the SCADA Realtime Support group.

Attachments: *N/A*

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-4.38
Respondent:	M. Elliott Andahazy
Page:	1 of 1

Question: What is the total number of DTE Electric staff currently working in the ESOC? Please list them by department or area. Please also provide the total number of DTE Electric staff in each area and identify those that are not currently working in the ESOC due to remote work or other work arrangements.

Answer: As stated in STDE-4.37, all SOC and Central Dispatch employees (including their leadership), are currently working in the ESOC while about half of the Operational Engineering employees are working in ESOC while the other half are working remotely due to the COVID-19 pandemic work rules. The SCADA Realtime Support team have all moved into the new ESOC and are working a hybrid model which is a combination of on-site and remote work mix. On any given day there will be up to 50% of the team on-site and the remainder working remotely. All of the Employees will participate in an on-site/remote work rotation. At any time, the full team can be required to work at the site as the team mission requires.

Department	Total # Employees	# Employees working in ESOC	# Employees working remotely
SOC	80	80	0
Central Dispatch	50	50	0
Operational Engineering	30	15	15
SCADA Realtime Support	22	22 Hybrid	0

Attachments: *N/A*

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.261
Respondent:	S. Hartwick
	1 of 1

Question: Refer to Table 11 on page 36 of Ms. Kartwick's direct testimony. Please provide the amount of cost savings that you plan to realize in 2022 and 2023 in each of the listed areas.

Answer: This information can be found in Exhibit A-22 – please note the costs below account for inflation. Table 11 was unadjusted for inflation to give a comparison of costs before and after the Surge.

Estimated Tree-related Annual Cost savings ($ millions)			
Cost Category		2022	2023
Tree-Related O&M	Tree Trim Reactive	16.2	15.0
	Tree Trim Storm	15.0	13.2
	Other DO – Service Operations Storm and Trouble	11.3	10.0
Tree-Related Capital	Tree Trim Reactive	2.9	2.5
	Tree Trim Storm	17.2	15.1
	Other DO – Service Operations Storm and Trouble	69.6	61.2

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-6.181d
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to page 59, lines 1-8 of Ms. Pfeuffer's direct testimony. Please:
d. What happens if the Company makes the necessary capital investments and the expected SAIDI level is not achieved in 2025? How will the Company be held accountable for lack of results?

Answer: DTE Electric objects to the request for the reason that it seeks a legal opinion, which is not a proper subject for discovery. In further answer and without waiving the objection, the Company would state as follows:

With the necessary investments, the Company expects to reach the All Weather SAIDI forecast for 2025 with average weather, and possibly sooner with more favorable weather. The Company cannot speculate on what might happen if the forecasted All Weather SAIDI is not reached.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-3.7c
Respondent:	J. Morren
Page:	1 of 2

Question: Please provide the following information related to the Company's approval process for capital projects for its generation fleet:

c) Please provide the project approval status of each qualifying project shown on Exhibit A-12, Sch. B-5.1, pages 2 and 4 through 7, and Exhibit A-12, Sch. B-5.2. For projects that have not received internal budgetary approval, please provide the expected date of such approval.

Answer: All capital projects for MERC and Fuel Supply shown in Exhibit A-12 Sch. B-5.2 have been approved.

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

Exhibit A-12 Schedule B5.1 page 2:

- Line 4, Monroe Bottom Ash Conversion (ELG) – full authorization expected fall 2022
- Line 5, Monroe FGD Wastewater (ELG) – full authorization expected beyond 2022
- Line 12, Monroe Fly Ash Basin Closure (CCR) – full authorization expected beyond 2022
- Line 17, River Rouge Decommissioning – full authorization expected in 2023
- Line 18, St. Clair Decommissioning – full authorization expected in 2023
- Line 19, Trenton Channel Decommissioning – full authorization expected in fall 2022
- Line 29, Blackstart Infrastructure, Site Security, & NERC Compliance – full authorization expected in summer 2022
- Line 31 – Slocum Battery Pilot – full authorization expected in spring 2022

Co-Respondent(s): D. Milo

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-3.7c
Respondent:	J. Morren
Page:	2 of 2

Exhibit A-12 Schedule B5.1 page 6:

- Line 112, Belle River Unit 2 LP Turbine Rotor & Blades – full authorization expected spring 2022
- Line 146, Renaissance Unit 1 Peaker Turbine Combustion Cans & Hot Gas Path Blades – full authorization expected spring 2022

Exhibit A-12 Schedule B5.1 page 7:

- Line 150, Belle River Unit 2 LP Turbine Rotor & Blades – full authorization expected spring 2022
- Line 161, Greenwood Unit 1 LP Turbine Rotor & Blades – full authorization expected summer 2022
- Line 181, Monroe Unit 3 Waterwall Tubes – full authorization expected fall 2022
- Line 197, Renaissance Unit 1 Peaker Turbine Combustion Cans & Hot Gas Path – full authorization expected spring 2022

Attachments: None.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

Exhibit: AG-1.14
Case No: U-20836
May 19, 2022

Power Generation Capital Projects without Full Authorization

Line #	Exhibit A-12 Sched B5.1, p. 2 Line No.	Project Description			10 ME Oct 2022	12 ME Oct 2023
1	4	Monroe Bottom Ash Conversion (ELG)			$ 8,406	$ 6,667
2	5	Monroe FGD Wastewater (ELG)			833	1,000
3	12	Monroe Fly Ash Basin Closure (CCR)			667	966
4	17	River Rouge Decommissioning			10,439	18,669
5	18	St. Clair Decommissioning			12,083	14,647
6	19	Trenton Channel Decommissioning			11,602	31,686
7	29	Blackstart Infrastructure, Site Security, & NERC Compl.			882	17,401
8		**Total**			**$ 44,912**	**$ 91,036**
9						
10	**Exhibit A-12**					
11	**Sched B5.1, p. 6**					
12	**Line No.**		**2022**			
13	112	Belle River Unit 2 LP Turbine Rotor & Blades	2,446		2,038	408
14	146	Renaissance Unit 1 Peaker Turbine Combustion	9,149		7,624	1,525
15					**$ 9,663**	**$ 1,933**
16						
17	**Exhibit A-12**					
18	**Sched B5.1, p. 7**					
19	**Line No.**			**2023**		
20	150	Belle River Unit 2 LP Turbine Rotor & Blades		5,417		4,514
21	161	Greenwood Unit 1 LP Turbine Rotor & Blades		4,168		3,473
22	181	Monroe Unit 3 Waterwall Tubes		1,042		868
23	197	Renaissance Unit 1 Peaker Turbine Combustion		12,221		10,184
24		**Total**				**$ 19,040**
25						
26	**Grand Total**				**$ 54,575**	**$ 112,009**

Source: Exhibit A-12, Schedule B5.1 and DR STDE-3.7c.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

MPSC ORDER OF February 4, 2021 IN CASE NO. U-20645

EXHIBIT AG-1.15 CONSISTS OF THIS COVER PAGE AND 16 PAGES

CONTAINING THE MICHIGAN PUBLIC SERVICE ORDER OF FEBRUARY 4, 2021 IN CASE NO. 20645

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to establish MI Power Grid.	)))	Case No. U-20645

At the February 4, 2021 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Tremaine L. Phillips, Commissioner
Hon. Katherine L. Peretick, Commissioner

ORDER

Background

On October 17, 2019, the Commission issued an order (October 17 order) opening this docket for the purpose of providing the impetus, vision, objectives, process, and next steps for the MI Power Grid initiative established by the Commission in partnership with Governor Gretchen Whitmer.

MI Power Grid is a focused, multi-year stakeholder initiative to maximize the benefits of the transition to clean, distributed energy resources (DERs) for Michigan residents and businesses. MI Power Grid seeks to engage utility customers and other stakeholders to help integrate new clean energy technologies and optimize grid investments for reliable, affordable electricity service. The initiative includes outreach and education as well as changes to utility regulation designed to advance Michigan's clean energy future.

In continuing efforts to assist in Michigan's transition to a modern, clean, customer-focused energy system MI Power Grid will better integrate ongoing and future discussions and decision making in three core areas of emphasis: (1) customer engagement, (2) integrating emerging technologies, and (3) optimizing grid investments and performance.

In the October 17 order, the Commission provided dates for the filing by the Commission Staff (Staff) of the first status report on utility pilot projects (due June 30, 2020), and the first status report on MI Power Grid (due September 30, 2020). On May 19, 2020, in recognition of the effect of the COVID-19 outbreak, the Commission issued an order extending those filing dates to September 30, 2020, and October 15, 2020, respectively. In the October 17 order, with regard to the MI Power Grid status report, the Commission stated:

> [T]he Commission directs the Staff to file a MI Power Grid status report on or before September 30, 2020, in this docket. The report shall detail actions taken to date, the status of the work areas, and any recommendations for Commission consideration. In addition, the Commission expects publication of an overview of actions taken as part of a final report issued in the third quarter of 2021.

October 17 order, p. 10.

On September 30, 2020, the Staff filed its Utility Pilot Best Practices and Future Pilot Areas report (pilot report) highlighting the efforts of the Energy Programs and Technology Pilots Workgroup (workgroup), stakeholder process, and the Staff's findings and recommendations.

On October 15, 2020, the Staff filed its MI Power Grid status report (October 15 MI Power Grid status report) which recognized the efforts of the workgroup and summarizes the Staff's pilot report. In the October 15 MI Power Grid status report the Staff stated:

> Given the importance of the remaining work areas, and the need to ensure adequate time for stakeholder efforts, Staff review and recommendations, and Commission action, the Commission should consider requesting Staff to submit a second status report during the third quarter of 2021, and extending the deadline for the MI Power Grid final report until 2022, in order to allow for a fuller accounting of MI Power Grid activities.

October 15 MI Power Grid status report, p. 23.

On October 29, 2020, the Commission issued an order (October 29 order) which reviewed the pilot report and recommendations, directed the Staff to create an online Michigan Pilot Directory, and requested comments regarding the adoption of a definition of the term "pilot" and objective criteria for pilot program review, to be filed no later than December 11, 2020.

Comments

On December 10, 2020, DTE Electric Company and DTE Gas Company (collectively DTE) and Michigan Electric and Gas Association (MEGA) filed comments. Additionally, on December 11, 2020, Consumers Energy Company (Consumers) and Advanced Energy Economy and the Michigan Energy Innovation Business Council (together AEE/MEIBC) filed comments.

In its comments, DTE states that it recommends that the Commission continue existing requirements and not add any unnecessary duplication. Specifically, DTE avers that it is "presently required to justify the prudence of all costs for which it requests recovery" and "is obligated to explain which costs will be incurred in the bridge period and test year." DTE's comments, p. 1. DTE further indicates that, while it attempts to highlight a future spend if a pilot spans across multiple rate cases, "it must still request recovery in the relevant rate case." *Id.* DTE also contends:

> Pilots are initiated and designed to learn about how one or more interventions generates one or more outcomes. One of those outcomes is often comparing the cost of the intervention to the impact of the intervention. That learning will then inform how the intervention compares to other technologies, approaches, or methods on a cost-effectiveness basis and a performance basis. If the underlying motivation for the pilot is to learn about the characteristics of the outcomes generated by the intervention, it is not possible to prospectively know if the intervention is or is not cost-effective at scale.

Id. Therefore, DTE contends that it is not appropriate to apply a cost-effectiveness test to pilot programs at the outset and that the Commission should consider pilot program proposals on the merits of the program instead.

In addition, DTE specifically comments on the requirement to share any added benefits to ratepayers or the energy delivery system, arguing that the "[f]ull implementations and general business optimizations that generate cost savings are already effectively shared with customers over the long term through reductions in the revenue requirement." *Id.*, pp. 1-2. Similarly, DTE states that impacts on reliability, resilience, safety, and ratepayer bills are already presented in the company's justification of prudence of a proposed pilot program and its costs. Further, DTE indicates that assessing long-term employment or business opportunities prior to the implementation of a pilot program would be inappropriate as it would require broad assumptions and speculation and that it believes the goal of investing in Michigan "is most effectively pursued on a holistic, company-wide basis and not on a pilot-by-pilot basis." *Id.*, p. 2. Overall, DTE avers that the public interest criteria should align with existing practices regarding cost reductions, investment objectives, and supply chain reporting. *Id.*, p. 1.

MEGA comments that it generally agrees with the proposed definition of "pilot" but that "pilot programs may also be limited in scope, size, scale, and geography in a manner that non-experimental offerings would not" and that "consideration of these additional aspects of potential pilots should be incorporated into the definition to provide clarity[.]" MEGA's comments, pp. 1-2. MEGA notes that the proposed objective criteria should only be applicable if a utility applies for pilot program approval outside of a general rate case or integrated resource plan proceeding. *See*, MEGA's comments, p. 2, n. 3. MEGA also recommends the addition of three additional criteria as follows: (1) Section 1.c. "to include references to any pending applicable regulatory dockets, legislation or other considerations that is relevant to the project;" (2) Section 3.d. to include "the proposed rate recovery approach so the Commission has greater understanding of the utility's holistic consideration of the project and opportunity for agreement, which will incentivize the development of these programs;" and (3) Section 6.f. "to allow for addition of any other public benefits." *Id*., p. 2. MEGA avers that Section 2.b. should be modified "to include location-driven programs and supporting rationale." *Id*. Additionally, MEGA notes membership concerns regarding the phrase "clean, distributed energy resources" in Section 6.a., arguing that this phrase "may be used to advocate against natural gas utility pilots or preclude pilot programs not specifically targeting clean energy solutions but addresses reliability, safety, or equity for example." *Id*.

MEGA further seeks clarification regarding the objective criteria proposed and the energy waste reduction (EWR) pilot program guidance established in Case No. U-15800 and notes that it "supports maintaining the well-established approach set for EWR as-is and utilizing the proposed methodology in this docket for other types of projects." MEGA's comments, p. 2. MEGA also notes that there is inherent potential for failure in pilot programs and recommends that the Commission provide "some direction and level of certainty on the treatment of projects that do not, cost-effectively produce the results anticipated despite prudent utility efforts to undergo the pilot." *Id*., p. 3.

In comments, Consumers avers that adopting the Commission's proposed "pilot objective criteria without a streamlined regulatory process and dedicated funding for early-stage pilot exploration will indirectly harm utility customers." Consumers' comments, p. 4. Consumers contends that the objective criteria set a high burden of proof for pilot programs especially early-phase small scale pilots which will delay the implementation of innovative pilots. As such, Consumers emphasizes the need for a streamlined regulatory approach for both gas and electric pilot programs. Consumers also argues that the *ex parte* process does not provide the necessary clarity with respect to funding approval which must be addressed through a contested proceeding.

Consumers proposes that the Commission adopt a process, similar to the EWR pilot process, for non-EWR pilots because "[d]edicated funding for early phase pilots could reduce the pilot lifecycle time and help streamline the collection of information to meet the [Commission's] objective criteria" and that an annual budget of $2 to $3 million "would be sufficient for pilot testing and exploration prior to filing for regulatory pilot approval, where additional details would be shared with the Commission and interested stakeholders." Consumers' comments, p. 5. Consumers also opines that the adoption of the proposed definition and objective criteria should not affect the EWR process. Finally, with respect to Section 6, Consumers avers that "the scope should be expanded to capture environmental benefits including sustainability and long-term decarbonization of the gas business" because, currently, it is "narrowly focused on electric and capturing benefits of distributed energy resources." *Id*., p. 6.

AEE/MEIBC comments that well-designed pilots are more urgent now in light of Executive Directive (ED) 2020-10, which sets forth a defined path for Michigan to reach economy-wide decarbonization. AEE/MEIBC also contends that the use of the term "measure" in the definition of "pilot" is too narrow because "pilots are increasingly likely to test multiple technologies and solutions to meet various grid and customer needs." AEE/MEIBC's comments, p. 2. Regarding the objective criteria, AEE/MEIBC notes its support but recommends that the Commission also "provide guidance on the specific policy outcomes the Commission would like the pilots to support." *Id*. AEE/MEIBC also recommends that the Commission increase stakeholder reporting requirements by requiring utilities to file reports regarding pilot plans, results, and data in the docket. Noting that the benefits of pilot programs can be diverse, AEE/MEIBC recommends that the Commission provide a framework methodology for utilities to estimate net benefits and require pilot proposals to "include information on how they would scale, if successful, and reports on pilots should refine these estimates." *Id*., p. 3. AEE/MEIBC also seeks clarification of Section 6.c. regarding whether it refers to "pilot participants, the impact of the pilot on all ratepayers, or the ratepayer bill impacts of a full-scale program based on the pilot." *Id*.

Discussion

The Commission first notes its agreement with the Staff's recommendations regarding the timing of the remaining MI Power Grid status reports. Thus, the Commission directs the Staff to submit a second MI Power Grid status report during the third quarter of 2021, and extends the deadline for the final MI Power Grid report to the third quarter of 2022, and in no case later than October 1, 2022.

The Commission appreciates the comments and feedback provided regarding the proposed "pilot" definition and objective criteria and again notes that continued collaboration is necessary to support the efforts of the workgroup, to implement the Staff's recommendations, to provide more analytical rigor in the review of pilots, and to facilitate additional discussions about ongoing and future pilot programs.

The Commission has reviewed the comments filed and notes its agreement with AEE/MEIBC's comments regarding the term "measure" in the proposed definition. Therefore, the Commission modifies the proposed definition, and adopts the definition of "pilot" as follows: "A pilot is a limited duration experiment or program to determine the impact of a measure, integrated solution, or new business relationship on one or more outcomes of interest." The Commission recognizes the importance of including existing terminology such as EWR pilot programs. The

Commission also wants to ensure utilities are pursuing dynamic approaches to solving issues and the addition of integrated solutions to the definition recognizes the importance of pilots seeking to solve a problem rather than testing a single measure. Similarly, the Commission acknowledges the importance of exploring new business relationships and not just technology, especially considering recent orders by the Federal Energy Regulatory Commission (FERC),[1] and that early and thoughtful collaboration between utilities and third parties will be necessary to ensure compliance and to minimize any potential issues.

Therefore, for all proposals that meet this pilot definition and that are submitted to the Commission for funding approval, utilities shall file a comprehensive pilot plan that includes the objective criteria, set forth in Exhibit A and discussed below, to be evaluated by the Commission. As is noted in Exhibit A, the "provision of data listed in the objective criteria is not envisioned to guarantee funding approval" and the "failure to provide information for some of the listed criteria or subcomponents is not envisioned to automatically lead to funding rejection."

In addition, the Commission also finds merit in modifying the proposed objective criteria as follows:

1. Pilot need and goals detailed.
a. Need for the pilot is expressed. Results of past similar pilots and findings are shared to justify the need for the proposed pilot.
b. Pilot goals and desired learnings detailed.
c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.

2. Pilot design and evaluation plan designed and presented together.
a. Pilot program design and evaluation plans are designed together so examined metrics and collected data support evaluation of the pilot in meeting goals and desired learnings.

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[1] On September 17, 2020, FERC issued Final Rule, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. RM18-9-000, 172 FERC ¶ 61,247 (Order 2222).

b. If applicable, define target customer population, selection rationale (including those for location-driven programs), recruitment plans, and evaluation plans for customer adoption and satisfaction.
c. If statistical analysis will be conducted on pilot results, a statistically significant sample size must be selected, supported, and detailed. If a statistically significant sample size is not selected, justification must be provided.
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.
e. If changes are required during implementation, pilot design, and evaluation impacts are shared.

3. Pilot project costs detailed.

a. Project costs are detailed by source and amount for applicable periods.
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described.
c. Anticipated cost-effectiveness and net benefits when deployed at scale described.
  i. Quantification of expected benefits of the pilot and the evaluation criteria/methods used.
d. Proposed rate recovery approach detailed.

4. Project timeline detailed.

a. Proposed timeline for the pilot project and any related reports or evaluations delineated.

5. Stakeholder engagement plan detailed.

a. Stakeholder engagement plan before, during, and after pilot takes place detailed.
b. Interim and final stakeholder reporting described.
c. Expected publicly available data from pilot shared under proper protections and privacy.

6. Public interest detailed.

a. Public interest justification, including supporting the transition to clean, distributed energy resources; enhancing reliability, safety, affordability, or equity; or other related goals, and the pilot's expected impacts described.
b. Any added benefits to ratepayers or the energy delivery system, either due to proposed site selection or through other pilot variables, especially if any system weaknesses or forecasted needs are addressed, shared.
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.
  i. Pilot reduction goals for metrics like customer bill, outage minutes/frequency, and OSHA reportable, as well as the translation to full deployment expectations.

d. Expected local or Michigan-based employment and business opportunities created by pilot described.
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.
f. Any other public benefits detailed.

In making these modifications, the Commission acknowledges the comments submitted and appreciates the feedback from stakeholders. The addition of Section 1.c., as proposed by MEGA, is reasonable as it will provide additional context in the consideration of pilot program proposals. In the comments, stakeholders specifically referenced Governor Whitmer's ED 2020-10, issued on September 23, 2020, which announced the "MI Healthy Climate" Plan. ED 2020-10, in conjunction with Executive Order 2019-12, set forth a statewide goal of decarbonization which is a reasonable driver for future pilot program proposals and could be considered as a driver for a pilot program proposal.

The Commission recognizes that, even though a pilot program may not be initially cost-effective, consideration must be given to whether the pilot program will grow into a cost-effective program when deployed at full scale. Moreover, quantification of expected benefits is essential for the Commission to consider in reviewing pilot program proposals through the ratemaking process. The Commission also recognizes that there are ongoing conversations about the appropriate benefit/cost considerations, specifically in distribution planning, but concludes that it is reasonable, in the meantime, for utilities to provide their internal scorecard, evaluation process, performance measurements, and other measures that may serve as the basis for pursuing full deployment. In addition, the Commission finds value in requiring an outline of the rate recovery timeline of the pilot, as this will help to illustrate rate impacts over the project timelines.

The Commission also recognizes the concerns raised pertaining to the current EWR pilot process and the inherent potential for failure in pilot programs. The Commission reiterates that adopting the proposed definition and objective criteria should not impact the current EWR pilot process[2] and notes that failure can provide an opportunity to learn and will not, in itself, be a bar to cost recovery. The Commission has previously found that reasonable and prudent pilot expenditures can still be deemed recoverable expenses irrespective of whether the pilot indicates a go-forward decision. *See e.g.,* November 4, 2010 order in Case No. U-16191.

In conclusion, the Commission appreciates the work of the utilities, other stakeholders, and the Staff throughout this process. As previously noted, the Commission's goal is to provide more analytical rigor to the review of utility pilots, additional follow-up to determine where pilots are headed, and to allow for additional information sharing.

THEREFORE, IT IS ORDERED that:

A. The Commission Staff shall file in this docket a second MI Power Grid status report in the third quarter of 2021, and shall file the final MI Power Grid report in the third quarter of 2022, and in no case later than October 1, 2022.

B. The Commission adopts the definition of "pilot" and objective criteria as listed in the attached Exhibit A, and finds that for all proposals that meet this pilot definition and that are submitted to the Commission for funding approval, utilities shall file a comprehensive pilot plan including the objective criteria to be evaluated by the Commission.

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[2] The Commission does, however, envision that EWR pilot programs will be included in the Michigan Pilot Directory, as discussed in the October 29 order.

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Tremaine L. Phillips, Commissioner

Katherine L. Peretick, Commissioner

By its action of February 4, 2012.

Lisa Felice, Executive Secretary

PROOF OF SERVICE

STATE OF MICHIGAN)

Case No. U-20645

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on February 4, 2021 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna J. Brown

Brianna Brown

Subscribed and sworn to before me
this 4th day of February 2021.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

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MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-3.96a
Respondent:	J. Morren
	1 of 1

Question: Refer to page 34, lines 22-25 of Mr. Morren's direct testimony. Please:

a. Provide the MMBtu of natural gas that the proposed hydrogen plant would displace during a full year of operation and how many tons per year of CO2 emissions would be avoided.

Answer: The hydrogen plant under the planned pilot operation would displace 31,776 MMBtu of natural gas and 1,861 tons of CO2 annually based on the proposed 18% capacity factor.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-3.96b
Respondent:	J. Morren
	1 of 1

Question: Refer to page 34, lines 22-25 of Mr. Morren's direct testimony. Please:
b. Provide the total tons of CO2 and other emissions generated by BWEC from burning 100% natural gas during a full year of operation.

Answer: BWEC is projected to emit approximately 3.3 million tons of CO_2 and 100 tons of NOx during a full year of operation.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-3.103a
Respondent:	J. Morren
	1 of 1

Question: Refer to page 43, lines 1-7 of Mr. Morren's direct testimony. Please:

a. Confirm that the $33.7 million cost of the battery pilot project translates to an equivalent cost of $2.4 million per MW installed. If confirming, please explain why such a project makes economic sense, given that CONE for new capacity in MISO Zone 7 is currently $94,000 per MW. If not confirming, please explain and provide the correct equivalent cost.

Answer: Confirmed. As stated in response AGDE-3.102b, there are multiple factors in addition to cost of installation that justify the Slocum battery pilot project as reasonable and prudent. See the Commission Order dated February 4, 2021 in Case No. U-20645 stating that, "a pilot may not be initially cost effective". The Company has outlined a plan for the pilot in accordance with the Commission's guidelines in Case No. U-20645 and as detailed in my Exhibit A-12, Schedule B5.1.3. CONE is priced at the cost of simple cycle gas peakers that have characteristics that differ greatly from lithium ion battery storage systems.

Attachment: None.

Exhibit: AG-1.18

CONFIDENTIAL

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-3.92b
Respondent:	J. Morren
	1 of 1

Question: Refer to page 30, lines 13-25 of Mr. Morren's direct testimony. Please:

b. Identify what specific incremental costs by item were incurred in the total amounts of $4.3 million and $8.1 million due to the suspension of the project for six weeks and for the post-suspension related to Covid-19.

Answer: The $4.3 million was related to a 6-week suspension of work due to the initial breakout of COVID in early 2020 as workplace shutdowns occurred across Michigan. The $8.1 million was associated with continued reduced productivity due to COVID-related illness and quarantine, reduced productivity due to COVID protocols, and increased overtime due to the lost productivity through the remainder of the project.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-2.9b
Respondent:	J. Morren
Page:	1 of 1

Question: Witness Morren describes 3 contingency events related to the construction of BWEC, including costs related to the suspension of work due to the COVID- 19 pandemic, that total to $9.7 million. He then states that the additional $8.1 million in contingency available will be consumed by additional suspension costs related to the pandemic. Please identify:

b. Identify the total in actual contingency expenses related to suspensions costs from the COVID-19 pandemic by month to the most recent month with data available.

Answer: $4.3 million was booked to the project in June 2020 related to a 6-week suspension of work due to COVID. The remaining $8.1 million was booked to the project in December 2021 as part of a larger COVID-driven expense that will be reconciled once the project is complete and all costs are finalized.

Attachments: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.219a
Respondent:	J. Davis
	1 of 2

Question: Refer to page 10, lines 15-25 of Mr. Davis' direct testimony. Please:
a. Explain why $24.8 million for a security video system is not an excessive cost for such a system. Provide evidence otherwise.

Answer: The projected costs for the security computer system are reasonable and prudent to achieve the objective of replacing the full security computer system, which includes computer servers, video cameras and other detection devices to alert plant security of security risks and to maintain positive surveillance of the Fermi 2 Power Plant.

Projected costs, scope and schedule for the security computer system were provided in Part III, Attachment 9.3. These projected costs, scope and schedule are best effort projections and contain no amounts for contingency.

Performing work at a U.S. commercial nuclear power plant such as Fermi 2 Power Plant involves unique considerations. I include as examples:

- Replacements such as security computer replacement are subject to strict design configuration controls to ensure plant design remains consistent with the Fermi 2 design basis and operating license; this requires detailed engineering analysis, calculations and design documents to be development prior to work execution as well as post-implementation.
- Work within the Fermi 2 Protected Area requires personnel to obtain and maintain special access approvals 24 hours per day, 7 days per week, 365 days per year to Fermi 2 Power Plant; all materials entering the Fermi 2 Protected Area must be hand-searched prior to entering the Protected Area.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.219a
Respondent:	J. Davis
	2 of 2

- The Fermi site covers approximately 1200 acres, is accessible by road, railway, and water, includes multiple buildings and, at times, hosts upwards of 2000 persons performing work.
- Excavation must be done using soft dig methods to ensure critical systems including systems providing nuclear-safety functions remain capable of performing their function.
- In general, the existing systems must remain operable while the replacement work is occurring.
- Electronic equipment, computers and other plant interfacing systems must be compliant with cyber security regulations which impose strict manufacturing, shipping, receipting and warehousing requirements.

Attachment: None

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.219b
Respondent:	J. Davis
	1 of 1

Question: Refer to page 10, lines 15-25 of Mr. Davis' direct testimony. Please:
b. Provide a list of what the $24.8 million will be spent on.

Answer: My testimony at line of page JCD-10 describes the aspects of the scope of the project. Additional cost projections, scope and schedule were provided in the Company's Part III Attachment 9.3.

Attachment: None

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.219c
Respondent:	J. Davis
	1 of 1

Question: Refer to page 10, lines 15-25 of Mr. Davis' direct testimony. Please:

c. Does the current security video system still work? If yes, why is it being replaced? If no, what problems or shortcomings does the current system have?

Answer: Failure of the Fermi 2 security computer system would compromise DTE Electric's commitment and obligation to provide physical security for the Fermi 2 Power Plant. The security computer system is being replaced to ensure continued operability of the system in accordance with the Fermi 2 physical security plan.

As discussed in my direct testimony, the security system computer is facing obsolesce issues that challenge the system's functionality today and these issues will likely become critical by 2024. Basis for replacement was provided in the Company's Part III Attachment 9.3.

Attachment: None

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.226d
Respondent:	J. Davis
	1 of 2

Question: Refer to Exhibit A-12, Schedule B5.3, pages 2 and 3. Please:

d. For the project on line 41, please explain what is being done with the plant wireless that will require $6.1 million from 2022 to the end of the projected test year. Explain why this cost for a wireless system is not excessive. Provide evidence otherwise.

Answer: The projected costs for the plant wireless system are reasonable and prudent.

Projected costs, scope and schedule for the plant wireless system were provided in the Attachment 9 of Part III. These projected costs, scope and schedule are best effort projections and contain no amounts for contingency.

Performing work at a U.S. commercial nuclear power plant such as Fermi 2 Power Plant involves unique considerations. I include as examples:

- Replacements such as the plant wireless system are subject to strict design configuration controls to ensure plant design remains consistent with the Fermi 2 design basis and operating license; this requires detailed engineering analysis, calculations and design documents to be development prior to work execution as well as post-implementation.
- Work within the Fermi 2 Protected Area requires personnel to obtain and maintain special access approvals 24 hours per day, 7 days per week, 365 days per year to Fermi 2 Power Plant; all materials entering the Fermi 2 Protected Area must be hand-searched prior to entering the PA.
- The Fermi 2 plant is a series of massive concrete structures. The plant wireless system must be designed to provide signals in every area of the plant.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.226d
Respondent:	J. Davis
	2 of 2

- The Fermi 2 plant contains equipment and instrumentation sensitive to radio signals. The plant wireless system must be designed to provide signals that do not interfere with the operation or functionality of plant equipment.
- In general, the existing systems must remain operable while the replacement work is occurring.
- Electronic equipment, computers and other plant interfacing systems (such as the plant wireless system) must be compliant with cyber security regulations which impose strict manufacturing, shipping, receipting and warehousing requirements.

Attachment: None

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.273a
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to page 20, lines 4-13 of Ms. Pizzuti's direct testimony. Please:
a. Provide the cost of the ACPP/TOU pilot program separately from the full implementation of TOU for each calendar year, bridge period, and projected test year from inception to completion. Provide the capital expenditures and O&M cost separately in Excel.

Answer: See the attached file.

Attachment: U-20836 AGDE-8.273a TOU_ACPP

					Case:	U-20836
					Request	AGDE-8.273a
					Respondent:	A. Pizzuti
Capital ($000)						
	Actual	**Actual**	**Actual**	**Projected**	**Projected**	
Calendar Year	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
ACPP	6,966	8,241	2,122			17,329
TOU				24,235	7,517	31,752
	Actual	**Actual**	**12 mo. end**	**end**	**12 mo. end**	
Test year	**2019**	**2020**	**12/31/21**	**10/31/22**	**10/31/23**	**Total**
ACPP	6,966	8,241	2,122			17,329
TOU				18,932	11,175	30,108
O&M ($000)						
	Actual	**Actual**	**Actual**	**Projected**	**Projected**	
Calendar Year	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
ACPP						
Deferred Regulatory Asset	165	3,015	2,929	1,190		7,299
O&M (1)	492					
	657					
TOU				7,117	9,983	17,100

(1) The Company spent $657,000 of O&M in 2019. We did not receive approval to defer the costs until November 2019; thus, a portion of the costs went directly to O&M.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.295a
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to pages 84-86 of Ms. Pizzuti's direct testimony on the Customer Pre-Pay project.
Please:
a. Provide the number of customers that have asked for a bill pre-pay program and provide any specific examples of those requests.

Answer: We do not have data on the number of customers who have asked for a prepay program.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.295d
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to pages 84-86 of Ms. Pizzuti's direct testimony on the Customer Pre-Pay project.
Please:
d. How many customers does the Company expect will use this program? Provide the basis for your forecast and the number of years after implementation of the program when this level of participation would be reached.

Answer: From our benchmarking, we have seen a wide range of enrollments reached by other utilities that have implemented a prepay program. The Company is targeting enrollment of 3,000 residential electric only customers in the first full year of the implementation in Phase 1 of the program, with the goal of enrolling up to 40,000 customers over a five-year period. The 40,000-enrollment goal presumes we implement Phase 2 of the program and expand eligibility for enrollment to a broader group of customers such as Dual Commodity customers. More details on enrollment eligibility requirements and enrollment goals for Phase 1 and Phase 2 are discussed in the Direct Testimony of Witness Michael J. Hatsios on page MJH-11, line 12 through page MJH-14, line 3 in Case No. U-21087, (2 T 37-39).

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.295f
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to pages 84-86 of Ms. Pizzuti's direct testimony on the Customer Pre-Pay project.
Please:
f. Provide the reduction in uncollectible accounts expense after three years from the start of the program and at the maximum level of expected participation.

Answer: As described in my testimony on page AMP-86, lines 1-8, potential reductions in arrears and uncollectible expense (UCX) that could result from the implementation of DTE's PrePay Program depends on many factors and assumptions leading to a wide range of potential outcomes driven by the size of the program and the segments of customers who choose to enroll. We have limited enrollment in Phase 1 of the program with the specific intent to learn from the data collected, including what the potential savings in UCX could be. These savings would not be material until after the test year in the instant case.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.295g
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to pages 84-86 of Ms. Pizzuti's direct testimony on the Customer Pre-Pay project.
Please:
g. Provide a copy of the cost/benefit analysis in Excel with formulas intact showing that this program is economically justified.

Answer: DTE IT assigns and utilizes a Project Prioritization Score (PPS) in place of traditional benefit cost analysis for prioritizing IT investments starting with the 2022 Annual Planning Cycle (APC). This method evaluates IT projects across multiple business benefit categories in addition to cost as shown in Figure 8 on page AMP-17. I provide more details on this prioritization process on page AMP-16 through AMP 17, Q20, of my testimony. The business cases in Exhibit A-24 Schedules N1.387, N1.388 and N1.389 on pages 522-527 also describe business benefits and outcomes supported by this project.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.286a
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to pages 41-42 of Ms. Pizzuti's direct testimony on the Digital Product Teams.
Please:
a. Explain what you mean by Digital Product Teams and what this project actually entails.

Answer: As described in my direct testimony in the instant case, the Digital Product Teams are dedicated groups of business and technical SMEs with responsibility for the enhancement of the customer transactional journeys (shown in Figure 3 on page AMP-8 of my testimony). The structure of the Digital Product Teams provides the required focus, with supporting agile processes that enable us to rapidly respond to changing customer needs and continually evolve digital products in alignment with those needs in a manner that provides distinctive digital customer experiences. We have a dedicated team that works in an agile manner to continually make and deploy improvements to our digital transactions per customer feedback and performance gaps such as low engagement or completion rates that signal there might be an issue in the digital process and in customer experience.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.286c
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to pages 41-42 of Ms. Pizzuti's direct testimony on the Digital Product Teams.

Please:

c. Identify specifically what the digital content is that is being developed and explain why it is critically necessary.

Answer: As new customer journeys are transformed and built in our digital channels, the corresponding new digital content also needs to be developed. The specific digital content includes the development of comprehensive layouts, interactive wireframes, and visual components as a part of creating the new digital web and mobile web experiences. These components are necessary to provide the software developers with direction on how the customer journey should be implemented.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.286d
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to pages 41-42 of Ms. Pizzuti's direct testimony on the Digital Product Teams.

Please:

d. Provide the tangible benefits and cost savings that would result from the implementation of this project on an annual basis and the year they would start.

Answer: DTE IT assigns and utilizes a Project Prioritization Score (PPS) in place of traditional benefit cost analysis for prioritizing IT investments starting with the 2022 Annual Planning Cycle (APC). This method evaluates IT projects across multiple business benefit categories in addition to cost as shown in Figure 8 on page AMP-17. I provide more details on this prioritization process on page AMP-16 through AMP 17, Q20, of my testimony. On page AMP-61-62 of my testimony, I describe the business outcomes in our five-year plan that we expect to achieve in our digital transactions that are supported by the Digital Product Teams. The business cases in Exhibit A-24 Schedules N1.344, N1.345 and N1.368 on pages 452-454 and 492 also describe the business benefits and outcomes supported by this project.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.286e
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to pages 41-42 of Ms. Pizzuti's direct testimony on the Digital Product Teams.

Please:

e. Provide the cost/benefit analysis that justifies spending the required capital on this project.

Answer: Please see my answer to AGDE-8.286d.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.288b
Respondent:	A. Pizzuti
	1 of 2

Question: Refer to pages 45 of Ms. Pizzuti's direct testimony on the Digital Transactional Experience. Please:
b. Explain why an additional $6.5 million was necessary in 2021 to make additional enhancements. Are additional capital expenditures planned in future years? If yes, when and for how much?

Answer: Building on what was achieved with MIMO DEG and Outage DEG projects in 2020, additional funding was necessary for increasing engagement and completion rates for both the MIMO and Outage digital experiences by improving digital process flows, providing more and clearer information to the customer, and simplifying navigation of the web and mobile web experiences.

For the MIMO web experience, investments in 2021 and planned through 2023 are focused on the MIMO transaction itself, improving address search success, re-sequencing transaction steps for greater customer ease, and providing clarity to the customer on where they are in the transaction as they navigate through the MIMO web customer journey.

The new functionality (see Figure 12 on page AMP-47 of my testimony for highlights) of the MIMO web and mobile web experience increased engagement rate from 19% in 2020 to 25% (in YTD 2021). Similar improvement was seen in the completion rates from 59% in 2020 to 64% (in YTD 2021).

For the Outage digital experience, investments in 2021 and planned through 2023 support on-going investment in improving the Outage web transaction and evolving the transaction based on feedback from customers and its performance during storms. For the Outage digital transaction, improvements in 2021 focused on increasing the usability, navigation, and usefulness of the Outage web transaction. With already high completion rates, Outage completion rates rose to 97.4% in YTD 2021 from 96.3% in 2020. Additional reporting upgrades included

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.288b
Respondent:	A. Pizzuti
	2 of 2

Police/Fire outage reporting, Municipality outage reporting, Streetlight reporting, and Downed-Wire reporting.

Yes, projects are planned in future years. As described in my testimony on page AMP-43, lines 4-6, the Digital Product Teams form the foundation for three project business cases: Digital Experience Group (DEG) in 2020, Digital Transactional Experience in 2021, and Journey Work Product Transformation Teams in 2022-2023. These projects, their costs, and the period in which these costs occur are shown in exhibit A-12, schedule B5.7.3, on lines 42, 43 and 49, respectively, and span the historical, bridge and test periods.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.288c
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to pages 45 of Ms. Pizzuti's direct testimony on the Digital Transactional Experience. Please:
c. Provide a copy the cost/benefit analysis in Excel with formulas intact that justifies undertaking this project and its prior phases.

Answer: DTE IT assigns and utilizes a Project Prioritization Score (PPS) in place of traditional benefit cost analysis for prioritizing IT investments starting with the 2022 Annual Planning Cycle (APC). This method evaluates IT projects across multiple business benefit categories in addition to cost as shown in Figure 8 on page AMP-17. I provide more details on this prioritization process on page AMP-16 through AMP 17, Q20, of my testimony. See Exhibit A-24, Schedule N1.345 on page 454 for additional information on the project.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.289b
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to page 49 of Ms. Pizzuti's direct testimony on the Collection Journey etc. Please:
b. Will these new features reduce or increase uncollectible costs?

Answer: We have not forecasted how adding the new digital transactions (features) would affect uncollectible expense. The intent of this project was to create a satisfying self-service transaction for our customers by providing them with an alternative way to request a promise to pay hold.

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.289c
Respondent:	A. Pizzuti
	1 of 1

Question: Refer to page 49 of Ms. Pizzuti's direct testimony on the Collection Journey etc. Please:
c. Provide the tangible benefits and cost savings that justify the total investment in this project.

Answer: We expect the tangible benefits from this project to include improvements in customer satisfaction by serving the customer in their channel of choice and a reduction in calls.

By making the Collection Restore and Promise to Pay transactions available in our digital channels (IVR and Web), we expect to reduce ~152,000 cumulative calls from 2022-2025, which we estimate can provide ~$875,000 of cumulative O&M savings over the period. See attachment "U-20836 Supplemental CR-1.2 Forecasted Call Reduction".

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-9.303b
Respondent:	T. Uzenski
	1 of 1

Question: Refer to page 55 of Ms. Uzenski's direct testimony discussing facilities upgrades at the Company's headquarters building. Please:

b. Explain what you mean by post-Covid flexible workspace and what this entails.

Answer: Employees will continue to work remotely and will be able to reserve workspaces as needed for occasional / intermittent on-site activities and meetings. Generally, employees will not have dedicated offices. Please see response to WA-1.2.

Attachment: *None*

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	WA-1.1
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: The following questions pertain to the Company's workforce:
1. What percentage of the Company's workforce is currently working remotely?

Answer:

Below are the results of a Gallup survey from fall last year where employees were asked to identify if they are working from home exclusively, at a DTE location, in the field, or a mix.

.

DTE Electric
Of 4,617 employees invited to the survey, 3,969 completed the survey for an 86% participation rate.
Of those 3,969 who responded,

- 814 said they were working from home exclusively, for a percentage of 21%
- 2,179 said they were working at a DTE location or in the field for a percentage of 55%
- 952 said they were working a mix of home and DTE location/in the field for a percentage of 24%

DTE Energy Corporate Services LLC
Of 2,736 employees invited to the survey, 2,538 completed the survey for a 93% participation rate.
Of those 2,538 who responded,

- 1,914 said they were working from home exclusively, for a percentage of 76%
- 297 said they were working at a DTE location or in the field for a percentage of 12%
- 313 said they were working a mix of home and DTE location/in the field for a percentage of 12%

Attachments: *None.*

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-9.312b
Respondent:	T. Uzenski
	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.8, pertaining to Capital Expenditures for Corporate Staff. Please:

b. For lines 2, 3, and 4, provide a breakdown of the costs by facility for each year shown in the schedule plus actual amounts for years 2019, 2021, and projected calendar years 2022 and 2023. Unless discussed in your testimony, identify the work to be done at each facility and why it is necessary. Provide this information in Excel.

Answer: See attachment for breakdown of costs by facility. The response to ABDE-1.10 describes the work done at each facility.

Attachment: *U-20836 AGDE-9.312b Facilities and Service Center Optimization.xlsx*

Michigan Public Service Commission					Case No.:	U-20836
DTE Electric Company					Audit Request:	AGDE-9.312b
Capital Expenditures					Date of Request:	4/21/2022
Facilities Construction and Upgrade					Respondent:	T. M. Uzenski
($000)					Page:	1 of 3

Line No	Description (a)	(b) Actual Year Ended 12/31/2019	(c) Actual Year Ended 12/31/2020	(d) Actual Year Ended 12/31/2021	(e) Projected Year Ended 12/31/2022	(f) Projected Year Ended 12/31/2023
1	Facilities Construction & Upgrade:					
2	Elevator - MNPP TH4 Full Modernization	504	(2)	-	-	-
3	Elevator - MNPP Reagent Bldg. Replace Elevator Controls	453	-	-	-	-
4	Elevator - WCB - Hi & Low Rise Elevator Controls	1,400	978	-	-	-
5	Elevator - MONPP TH1 elevator modernization	695	6	-	-	-
6	Elevator - MONPP TH2 elevator modernization	438	325	-	-	-
7	Elevator - GWEC-Admin Elev Mod	629	1	-	-	-
8	GO Freight Elevator Modernization	-	551	265	-	-
9	Edison Center - Replace fire alarm detection	932	1,494	69	-	-
10	WSC Bldg G Replace Electrical Infrastructure	3,620	11	-	-	-
11	WSC Bldg G Roof replacement	-	-	270	-	-
12	GO Combine North & South Service entrance replacement	934	131	10	-	-
13	GO Standpipe & Fire Pump replacement	775	247	-	-	-
14	GO Domestic water piping supply and sanitary replacement	399	1,833	2,538	-	-
15	Edison Center-GO replace update HVAC controls	230	858	2,461	-	-
16	SB GO Tunnel safety fix renovation	1,665	16	-	-	-
17	WSC Bldg G Fire Alarm	403	-	-	-	-
18	MONPP Turbine Rm OH Crane modernization	948	(19)	-	-	-
19	WCB Façade & Windows	130	7	2	-	-
20	Fermi 2 Reactor Bldg. Freight Elevator	486	878	-	-	-
21	NAEC Site Paving Drainage Replacement	-	981	1	-	-
22	Newport Sc Paving Phase 3	-	692	4	-	-
23	NAEC Paving East Lot	-	-	1,341	-	-
24	SB & Beech Street Roofs (GO Roof)	-	2,365	(2)	-	-
25	UST Program - Ann Arbor SC	-	213	677	-	-
26	WSC 75 Ton (2) OH Crane Modernization	-	1,949	1,693	-	-
27	GO Air Handling Unit (AHU) Distribution System Replacement	-	-	-	1,000	-
28	GO MCC Replacements	-	-	-	1,000	-
29	GO Distribution Panel Replacement	-	-	-	1,000	-
30	Electrical	-	-	-	1,500	3,000
31	Campus Fire Detection & Annunciation Sys Repl	-	-	-	1,200	4,000
32	Paving	-	-	-	4,200	4,000
33	Plumbing	-	-	-	700	600
34	Roofing	-	-	-	700	2,000
35	WCB Perimeter Baseboard Heat Replacement	-	-	-	2,000	-
36	WCB Substation & Distribution Replacement	-	112	624	3,000	-
37	GO Stand Pipe Fire Pump Upgrade Revision	-	-	137	-	-
38	WCB Distribution Chilled & Condenser Water Piping Replacement	-	-	-	500	-
39	Plaza Data Center Liebert AC Replacement	-	576	1	-	-
40	Plaza Distribution Panelboard Replacement	-	106	364	1,500	-
41	BRPP Turbine Rm OH Crane Modernization	-	251	749	-	-
42	GWEC Turbine Rm OH Crane Modernization	-	13	1,103	-	-
43	MNPP South Turbine Crane Controls	-	2,543	59	-	-
44	HVAC - various locations	-	-	-	7,451	7,829
45	Elevator various locations	-	-	-	3,901	4,424
46	Asset Preservation	487	10	-	-	-
47	Automotive Lift Program	659	1,034	799	1,000	1,000
48	Bird Netting	-	-	-	20	22
49	Construction	9,213	4,091	4,691	1,525	1,525
50	Crane	34	-	26	265	265
51	Dock Levelers	15	49	83	-	-
52	Door	957	237	1,187	912	912
53	Electrical	1,248	1,078	1,721	875	875
54	Elevator	264	345	132	741	331
55	Environmental	323	207	270	-	-
56	Equipment	412	383	1,610	-	-
57	Façade	80	-	35	694	694
58	Fire	587	107	103	626	626
59	Flooring	4	-	85	397	397
60	HVAC	6,303	3,591	6,891	3,750	3,750
61	Lighting	-	-	111	-	-
62	Paving	670	41	181	418	418
63	Plumbing	476	1,615	863	-	410
64	Roofing	275	(77)	1,078	325	325
65	Safety	472	2,728	1,098	-	-
66	Security	29	237	86	-	-
67	Structural	38	-	526	375	375
68	Tools	51	(1)	19	18	18
69	Window	172	106	144	150	150
70	Warehousing and Garage	-	-	24	-	-
71	Other	22	56	7	-	-
72	**Total Facilities Construction and Upgrade**	37,434	32,953	34,133	41,742	37,945

					Case No.:	U-20836
Michigan Public Service Commission						
DTE Electric Company					Audit Request:	AGDE-9.312b
Capital Expenditures					Date of Request:	4/21/2022
Facilities Renovation					Respondent:	T. M. Uzenski
($000)					Page:	2 of 3

	(a)	(b)	(c)	(d)	(e)	(f)
		Actual	**Actual**	**Actual**	**Projected**	**Projected**
Line		**Year Ended**	**Year Ended**	**Year Ended**	**Year Ended**	**Year Ended**
No	**Description**	**12/31/2019**	**12/31/2020**	**12/31/2021**	**12/31/2022**	**12/31/2023**
1	Beech Street	1,864	2,466	14	-	-
2	General Office (GO) Building - 1 South	28	-	-	-	-
3	General Office (GO) Building - 4th Fl	263	-	-	-	-
4	General Office (GO) Building - 5th Fl	(1)	-	-	-	-
5	General Office (GO) Building - 6th Fl	3,719	-	-	-	-
6	General Office (GO) Building - 7th Fl	2,996	1,789	-	-	-
7	General Office (GO) Building - 8 & 9th Fl	-	85	1,930	1,200	-
8	Greenwood Power Plant	175	-	-	-	-
9	Newport	(56)	-	-	-	-
10	Service Building 1st Floor	6,382	-	-	-	-
11	WCB 4th Floor Refresh	-	-	4,317	-	-
12	WCB 5th Floor Refresh	-	-	163	1,800	-
13	WCB 6th Floor	48	-	-	-	-
14	WCB 8th Floor	3,807	-	-	-	-
15	WCB 8th, 16th & 17 Floors Refresh	-	521	3,812	-	-
16	WCB 9th Floor	-	82	4,651	-	-
17	WCB 11th Floor	3,631	-	-	-	-
18	WCB 12th Floor	82	3,074	2,754	-	-
19	WCB 16th Floor	(12)	-	-	-	-
20	WCB 22nd Floor	3	2,107	3,361	-	-
21	WCB 23rd Floor	-	-	-	3,500	-
22	WCB 24th Floor	-	-	-	3,500	-
23	North Area Energy Center -Cass City	6,661	1,157	(9)	-	-
24	NAEC - CS	-	3,273	1	-	-
25	Other	-	-	-	-	-
26	**Total Facilities Renovation**	**29,589**	**14,555**	**20,995**	**10,000**	**-**

Michigan Public Service Commission				Case No.:	U-20836	
DTE Electric Company				Audit Request:	AGDE-9.312b	
Capital Expenditures				Date of Request:	4/21/2022	
Service Center Optimization				Respondent:	T. M. Uzenski	
($000)				Page:	3 of 3	
	(a)	(b)	(c)	(d)	(e)	(f)
		Actual	**Actual**	**Actual**	**Projected**	**Projected**
Line		**Year Ended**	**Year Ended**	**Year Ended**	**Year Ended**	**Year Ended**
No	**Description**	**12/31/2019**	**12/31/2020**	**12/31/2021**	**12/31/2022**	**12/31/2023**
1	WSC Bldg G Fire Alarm	-	930	40	-	-
2	Western Wayne SC Renovation	-	-	1,857	7,000	-
3	Warren Service Center Phase 1	11,549	867	-	-	-
4	Warren Service Bldg. H Demolition	-	2,145	6,128	-	-
5	HQ Pipe Support	-	958	-	-	-
6	WSC DeLab-HVAC Replacement	-	257	756	-	-
7	WSC Site Work	-	-	144	4,500	3,000
8	Farmington TSSC	-	-	330	-	-
9	Trombly Annex Demolition & Site Improvement	-	-	252	1,500	-
10	WSC Bldg. L	-	-	112	3,200	6,100
11	Generation Optimization Relocation	-	-	4,782	-	-
12	Dixie Warehouse Closure	-	-	-	-	2,000
13	Relocate Mech. Mailing	-	-	-	2,000	-
14	Close Wixom Pole Yard	-	-	-	2,000	3,000
15	WSC Paving - Bldg. G&F	-	864	5	-	-
16	WSC Bldg. H Renovation & Relocation	-	-	44	-	-
17	Warren Service Center - Labs	306	(4)	-	-	-
18	Waterford Service Center	6,510	872	1,993	10,000	24,000
19	New Training Development Center	-	-	-	-	5,000
20	DTE Branding Refresh - Roof Top Capital	337	4,842	-	-	-
21	DTE Branding Refresh - General Signage	1,602	(36)	-	-	-
22	Other	496	-	-	-	-
23	**Total Service Center Optimization**	**20,800**	**11,694**	**16,443**	**30,201**	**43,100**

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-9.304d
Respondent:	T. Uzenski
	1 of 1

Question: Refer to pages 55 and 56 of Ms. Uzenski's direct testimony discussing Service Center Optimization. Please:

d. Is the $4.5 million pertaining to the cancellation of the Wixom pole yard relocation still in Exhibit A-12, Schedule B5.8, and should be removed?

Answer: Yes, the cost is still in the exhibit and should be removed.

Attachment: *None*

MPSC Case No.:	U-20836
Requestor:	Staff
Question No.:	STDE-8.1a
Respondent:	T. Uzenski
	1 of 1

Question: Referencing the project "HQ Energy Center" detailed in the testimony of witness Uzenski:

a. What is the cause of the increase in construction costs that lead to this project exceeding the $39.4 million estimate used as the basis for its previous approval? Please provide specific cost categories and detail cost increases that result in the additional $8.2 million in forecasted project costs.

Answer: **The additional $8.4 million of forecasted project costs are due to the following:**

- Additional construction costs of $2.2M:
  - Pipe trestle modifications
  - COVID delays
  - Landscaping modifications
  - Repaving and repair to Plum and Elizabeth Streets
- Revised cost for new gas service $3.9M
- Engineering documentation resulting from scope changes and project closeout $0.3M
- Additional construction support including City of Detroit building code compliance $0.7M
- DTE project management $1.3M

Attachment: *None*

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

Exhibit: AG-1.26
Case No: U-20836
May 19, 2022

Adjustments to Capital Expenditures, Rate Base and Depreciation Expense

($000)

		Capital Expenditure Reductions [1]							Reduction in
				10 M/E	12 M/E		Rate Base	Depreciation	Depreciation
Line	Description	2020 & Prior	2021	Oct 2022	Oct 2023	Total	Reduction	Rate [2]	Expense
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Contingency Capita Expenditures**			$ 2,100		$ 2,100	$ 2,100	6.67%	$ 140
2	**Distribution Operations:**								
3	Electric System Major Equipment			5,797	7,183	12,980	9,389	4.09%	384
4	NRUC & Improvement Blankets			7,244	8,990	16,234	11,739	4.09%	480
5	General Plant, Tools & Equipment			2,177	2,698	4,875	3,526	4.09%	144
6	Strategic Capital Programs			208,907	251,997	460,904	334,906	4.09%	13,698
7	ADMS-MNS			2,334	2,883	5,217	3,776	4.09%	154
8	ESOC	6,069	14,062	369		20,500	20,500	4.09%	838
9	Tree Trimming Surge Program				9,080	9,080	4,540	4.09%	186
10	**Power Generation:**								
11	Projects Lacking Authorization			54,775	112,009	166,784	110,780	3.02%	3,346
12	Hydrogen Pilot Project		756	882	17,401	19,039	10,339	3.02%	312
13	Battery Energy Storage Systems		45	7,188	26,430	33,663	20,448	3.02%	618
14	Blackstart Infrastructure Improvements		3,860	32,354	11,353	47,567	41,891	3.02%	1,265
15	Blue Water Energy Center	4,300				4,300	4,300	3.02%	130
16	**Nuclear Operations:**								
17	Plant Facilities and Equipment	391	4,234	14,608	19,236	38,469	28,851	4.26%	1,229
18	**Customer Service**								
19	Advanced Customer Pricing & Time of Use			18,932	11,175	30,107	24,520	6.67%	1,635
20	DTE Pre-Pay Program		6,725	1,250	4,647	12,622	10,299	6.67%	687
21	Digital Product Teams		6,450	5,368	4,151	15,969	13,894	6.67%	927
22	**Corporate Facilities**								
23	Facilties Construction, Renovation & Optimization		3,172	11,223	9,086	23,481	18,938	7.58%	1,436
24	Headquarters Energy Center		5,200			5,200	5,200	7.58%	394
25	**Total**	**$ 10,760**	**$ 44,504**	**$ 375,508**	**$ 498,319**	**$ 929,091**	**$ 679,932**		**$ 28,003**
26									
27	Total Rate Base Deduction						**$ 679,932**		

Source: (1) See AG witness Coppola Direct Testimony.
(2) Depreciation rates from Exhibit A-13, Schedule C6, page 2. Incentive Compensation depreciation rate is the total Company average rate

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-20836
Exhibit AG-1.27
May 19, 2022

Recommended Capital Structure & Cost Rates for Test Year Ending October 31, 2023

(Millions of Dollars)

Line	Description (a)	Capital Structure: Capital Balances* (b)	% Permeant Capital (c)	% Total Capital (d)	Cost Rate** (e)	Total Cost (d) x (e) (f)	Conversion Factors*** (g)	Pre-Tax Wtd. Cost (f) x (g) (h)
1	Long Term Debt	$ 8,411.0	50.0%	39.55%	3.69%	1.46%	1.0000	1.46%
2	Preferred Stock	-	0.0%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Equity	8,426.0	50.0%	39.62%	9.50%	3.76%	1.3496	5.08%
4	Total Permanent Capital	16,837.0	100.0%	79.17%		5.22%		6.54%
5	Short Term Debt	265.5		1.25%	1.74%	0.02%	1.0000	0.02%
6	Deferred Income Taxes	4,118.0		19.36%	0.00%	0.00%	1.0000	0.00%
7	JDITC							
8	Long Term Debt	23.7		0.11%	3.69%	0.00%	1.0000	0.00%
9	Preferred Stock	-		0.00%	0.00%	0.00%	1.3496	0.00%
10	Common Equity	23.7		0.11%	9.50%	0.01%	1.3496	0.01%
11	Total Capitalization & Cost Rates	$ 21,267.9		100.00%		**5.26%**		**6.58%**

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-1.28
*** Conversion factors per Company Exhibit A-14, Schedule D1.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Summary of Cost of Common Equity Capital Analysis

Line	Description (a)	Relative Weighting (b)	Peer Group (c)	Note (d)
1	Discounted Cash Flow (DCF) Approach	50.00%	9.18%	1
2	Capital Asset Pricing Model Approach	25.00%	9.39%	2
3	Equity Risk Premium Approach	25.00%	8.93%	3
4	**Calculated Cost of Common Equity (Sum of Col. (b) x (c) for each line)**		**9.17%**	
5	**Adjustment for Other Factors**		**0.33%**	4
6	**Cost of Common Equity for Rate Case Purposes**		**9.50%**	

Note 1 See Exhibit AG-1.29
Note 2 See Exhibit AG-1.30
Note 3 See Exhibit AG-1.31
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
DTE Electric - Electric Rate Case

Discounted Cash Flow (DCF) Application
(See Equation Below)

Line	Company	Ticker	Stock Price*	Projected 2022-23 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	Allete	ALE	65.10	$ 2.65	4.07%	8.02%	5.67%	6.84%	10.91%
2	Alliant Energy	LNT	61.26	1.76	2.87%	4.32%	6.00%	5.16%	8.04%
3	Ameren	AEE	90.40	2.44	2.70%	6.45%	7.40%	6.93%	9.63%
4	Avista	AVA	45.14	1.80	3.99%	5.54%	5.90%	5.72%	9.71%
5	Black Hills	BKH	73.33	2.47	3.37%	5.98%	4.67%	5.32%	8.69%
6	Consolidated Edison	ED	91.52	3.20	3.50%	6.40%	2.00%	4.20%	7.70%
7	CMS Energy	CMS	68.01	1.89	2.78%	7.77%	8.10%	7.93%	10.71%
8	Dominion Energy	D	82.63	2.70	3.27%	10.48%	6.37%	8.42%	11.69%
9	Evergy	EVRG	65.91	2.31	3.50%	4.40%	5.12%	4.76%	8.26%
10	IDACORP	IDA	111.93	3.15	2.81%	4.35%	4.40%	4.37%	7.19%
11	Portland General Electric	POR	54.29	1.85	3.41%	5.17%	4.50%	4.84%	8.24%
12	WEC Energy	WEC	96.78	3.01	3.11%	6.00%	6.20%	6.10%	9.21%
13	Xcel Energy	XEL	70.76	2.02	2.85%	6.21%	6.90%	6.55%	9.41%
19	**Average**				**3.25%**	**6.24%**	**5.63%**	***5.94%***	***9.18%***

Notes
* High-Low Average Prices for the 30 days March 1 to April 11, 2022 per Yahoo
** From the Value Line Investment Survey Publications of February 11, March 11, and April 22, 2022
*** Columns (f) and (g) are from workpapers

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

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-20836
Exhibit AG-1.30
May 19, 2022

Capital Asset Pricing Model Application
(See Equation Below)

Line	Company (a)	Ticker (b)	Mkt. to Bk. Ratio of Com. Equity (c)	Current Beta (*B*) (d)	Risk Premium (R*p*) (e)	Beta x Risk Premium Col. (d) x (e) (f)	Projected 2022-23 Risk Free Rate (R*f*) (g)	K*e* or 2022-23 CAPM ROE for Proxy Co. Col. (e) + (f) (h)
1	Allete	ALE	1.46	0.90	7.25%	6.53%	3.20%	9.73%
2	Alliant Energy	LNT	2.57	0.85	7.25%	6.16%	3.20%	9.36%
3	Ameren	AEE	2.36	0.80	7.25%	5.80%	3.20%	9.00%
4	Avista	AVA	1.41	0.95	7.25%	6.89%	3.20%	10.09%
5	Black Hills	BKH	1.64	1.00	7.25%	7.25%	3.20%	10.45%
6	Consolidated Edison	ED	1.51	0.75	7.25%	5.44%	3.20%	8.64%
7	CMS Energy	CMS	2.94	0.80	7.25%	5.80%	3.20%	9.00%
8	Dominion Energy	D	2.33	0.85	7.25%	6.16%	3.20%	9.36%
9	Evergy	EVRG	1.70	0.95	7.25%	6.89%	3.20%	10.09%
10	IDACORP	IDA	2.14	0.80	7.25%	5.80%	3.20%	9.00%
11	Portland General Electric	POR	1.75	0.85	7.25%	6.16%	3.20%	9.36%
12	WEC Energy	WEC	2.81	0.80	7.25%	5.80%	3.20%	9.00%
13	Xcel Energy	XEL	3.38	0.80	7.25%	5.80%	3.20%	9.00%
15	**Average**		**2.15**	**0.85**	**7.25%**	**6.19%**	**3.20%**	***9.39%***
16	High							10.45%
17	Low							8.64%

Sources	Column (c)	Per Exhibit AG-1.34	
	Column (d)	From the Value Line Investment Survey Publications of February 11, March 11, and April 22, 2022	
	Column (e)	From AG Workpapers	
	Column (g)	Projected Year End 2022 Ten Yr. Treasury - per Kiplinger Apr. 14, 2022 Publication	3.0%
		March 1 to April 15,2022 Spread (30 Yr. vs. 10 Yr. Treasuries)	0.2%
		Risk Free Rate Used Above	**3.2%**

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-20836**
DTE Electric - Electric Rate Case | **Exhibit AG-1.31**
May 19, 2022
Electric Utility Equity Risk Premium Approach | **Page 1 of 1**

Line	Description (a)	Projected Test Period (c)	Note (d)
1	**Proxy Group Debt Ratings (S & P)**	**A to BBB**	1
2	**Number of Proxy Companies**	**13**	
	Build-up of Common Equity Rate of Return		
3	Long Term US Treasury Rate Projection	3.20%	2
4	Corporate Spread Over Treasury Bond Rate	1.38%	3
5	Sub Total (Line 2 + Line 3)	4.58%	
6	Historical Spread - Utility Common Stocks over Bonds	4.35%	4
7	**Cost of Common Equity (Line 5 + Line 6)**	***8.93%***	

Notes
1 The peer group contains companies rated in either the "A" or "BBB" categories (10 of 13 rated BBB or not rated)
2 See risk free rate from AG CAPM analysis
3 Determined as follows.

		Basis Pts.
Average 2021 Spread for "A" rated category issues from Exhibit A-18, Sched. H2		101
June 7, 2021 issue rates		
Duke Energy 30 Year Debt (Baa2 / BBB)	125	
Alabama Power 30 Year Debt (A1 / A)	88	
Difference		37
Total Spread to Line 4 above		138

4 Historical average per AG workpapers

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-20836**

DTE Electric - Electric Rate Case **Exhibit AG-1.32**

May 19, 2022

Electric Rate Case Return on Equity (ROE) Rates (2020 and 2021)*

ROEs Under 10%

	Electric Company	Jurisdiction & Order Date**			ROE Awarded in 2020	ROE Awarded in 2021	Parent Company	Pub. Finan'ls Avail.	Long Term Debt Issued Since Date of Rate Order
1	Consolidated Edison-NY	NY	Jan. 6	2020	8.80%		Consolidated Edison	Yes	Mar. 26, 2020: $1.7B, 10-30 Yr. @ 3.35% & 3.95%
2	Rockland Electric	NJ	Jan. 22	2020	9.50%		Consolidated Edison	Yes	Mar. 26, 2020: $1.7B, 10-30 Yr. @ 3.35% & 3.95%
3	Indiana Michigan Power	MI	Jan. 23	2020	9.86%		American Electric Power	Yes	Nov. 16, 2020: $1.5B, 3-5 Yr. @ 0.75% & 1.0%
4	Public Service-Colorado	CO	Feb. 11	2020	9.30%		Xcel Energy	Yes	Sep. 22, 2020: $500M, 3 Yr. @ 0.50%%
5	Houston Electric	TX	Feb. 14	2020	9.40%		CenterPoint	Yes	May 11, 2021: $1.0B, 5 & 10 Yr., 1.45% & 2.05%
6	Central Maine Power	ME	Feb. 19	2020	8.25%		Avangrid	Yes	Apr. 7, 2020: $750M, 5 Yr. @ 3.2%
7	Virginia Electric & Power	NC	Feb. 24	2020	9.75%		Dominion Energy	Yes	Dec. 1, 2020 : $900M, 30 Yr. @ 2.45%
8	AEP Texas	TX	Feb. 27	2020	9.40%		American Electric Power	Yes	Jun. 29, 2020: $600M, 10 Yr. @ 2.10%
9	Indiana Michigan Power	IN	Mar. 11	2020	9.70%		American Electric Power	Yes	Nov. 16, 2020: $1.5B, 3-5 Yr. @ 0.75% & 1.0%
10	Avista	WA	Mar. 25	2020	9.40%		Avista	Yes	Sep. 28, 2021:$70M, 30 Yr. @ 2.9%
11	Fitchburg Gas & Electric	MA	Apr. 17	2020	9.70%		Unitil	Yes	Sep. 2020 $27.5M,20 Yr. @ 3.58%
12	Duke Energy Kentucky	KY	Apr. 27	2020	9.25%		Duke Energy	Yes	May. 13, 2020: $500M, 10 Yr. @ 2.45%
13	DTE Electric	MI	May. 8	2020	9.90%		DTE Energy	Yes	Sep. 29, 2020: $750M, 2 Yr. @ 0.55%
14	Southwestern Pub. Serv.	NM	May. 20	2020	9.45%		Xcel Energy	Yes	Sep. 22, 2020: $500M, 3 Yr. @ 0.50%
15	Duke Energy Indiana	IN	Jun. 29	2020	9.70%		Duke Energy	Yes	Jun 2021: $2.5B, 10Yr, 20Yr, 30Yr @ 2.5% to 3.5%
16	Liberty Utilities	NH	Jun. 30	2020	9.10%		Algonquin Pwr & Utilities	Yes	Sep. 22, 2020: $600M, 10 Yr. @ 2.05%
17	Pudget Sound Energy	WA	Jul. 8	2020	9.40%			Private	
18	Delmarva Pwr. & Light	MD	Jul. 14	2020	9.60%		Exelon	Yes	Jun. 15, 2021: $800M, 10 Yr. at 2.25%
19	Hawaii Electric & Light	HI	Jul. 28	2020	9.50%		Hawaiian Electric Indust.	Yes	Sep. 29, 2021: $125M Var. Mat. & Rates
20	Green Mountain Power	VT	Aug. 27	2020	8.20%		Northern N.E. Energy	Private	
21	Southwestern Pub. Serv.	TX	Aug. 27	2020	9.45%		Xcel Energy	Yes	Sep. 22, 2020: $500M, 3 Yr. @ 0.50%%
22	Hawaiian Electric	HI	Oct. 22	2020	9.50%		Hawaiian Electric Indust.	Yes	Sep. 29, 2021: $125M Var. Mat. & Rates
23	Jersey Central Pwr. & Lgt.	NJ	Oct. 28	2020	9.60%		First Energy	Yes	Mar. 19, 2021: $500M, 11 Yr., @2.75%
24	NY State Electric & Gas	NY	Nov. 19	2020	8.80%		Avangrid	Yes	Sep. 24, 2021: $350M, 10 Yr. @2.15%
25	Rochester Gas & Electric	NY	Nov. 19	2020	8.80%		Avangrid	Yes	Sep. 24, 2021: $350M, 10 Yr. @2.15%
26	Appalachian Power	VA	Nov. 24	2020	9.20%		American Electric Power	Yes	Nov. 10, 2021: $750M, 41 Yr. @ 3.5%
27	Madison Gas & Electric	WI	Nov. 24	2020	9.80%		Madison Gas & Electric	Yes	May 2021: $100M, 10 Yr. @ 2.48%
28	Ameren Illinois	IL	Dec. 9	2020	8.38%		Ameren	Yes	Feb. 24, 2021: $450M, 7 Yr. @ 1.75%
29	Commonwealth Edison	IL	Dec. 9	2020	8.38%		Exelon	Yes	Jun. 15, 2021: $800M, 10 Yr. at 2.25%
30	Nevada Power	NV	Dec. 10	2020	9.40%		Berkshire Hathaway	Private	
31	Pacificorp	WA	Dec. 14	2020	9.50%		Berkshire Hathaway	Private	Jul. 7, 2021: 1 Bil., 30 Yr. @ 2.9%
32	Public Service Co - NH	NH	Dec. 15	2020	9.30%		Eversource	Yes	Mar. 8, 2021: $350M, 10 Yr. at 2.55%
33	Baltimore Gas & Electric	MD	Dec. 16	2020	9.50%		Exelon	Yes	Jun. 15, 2021: $800M, 10 Yr. at 2.25%
34	Consumers Energy	MI	Dec. 17	2020	9.90%		CMS Energy	Yes	Aug., 2021: $300M, 31 Yr. at 2.65%
35	Pacificorp	OR	Dec. 18	2020	9.50%		Berkshire Hathaway	Private	

* A summary of all ROEs including those at 10% and above is included on page 3 of this exhibi

**All ROE data from Regulatory Research Associates & excludes Ltd. Issue Rider

Electric Rate Case Return on Equity (ROE) Rates (2020 and 2021)*

ROEs Under 10%

Line	Electric Company	Jurisdiction & Order Date			ROE Awarded in 2020	ROE Awarded in 2021	Parent Company	Pub. Finan'ls Avail.	Long Term Debt Issued Since Date of Rate Order
1	Tucson Electric Power	AZ	Dec. 22	2020	9.15%		Fortis	FRN	
2	Pacificorp	UT	Dec. 30	2020	9.65%		Berkshire Hathaway	Private	Jul. 7, 2021: 1 Bil., 30 Yr. @ 2.9%
3	Average 2020 ROE Awarded under 10%(Pg. 1 & 2)				9.32%				
4	Kentucky Power	KY	Jan. 13	2021		9.30%	Amer. Elec. Power	Yes	Nov. 10, 2021: $750M, 41 Yr. at 3.5%
5	Duke Energy Carolinas	NC	Mar. 31	2021		9.60%	Duke Energy	Yes	Jun 2021: $2.5B, 10Yr, 20Yr, 30Yr at 2.5% to 3.5%
6	Duke Energy Progress	NC	Apr. 16	2021		9.60%	Duke Energy	Yes	Jun 2021: $2.5B, 10Yr, 20Yr, 30Yr at 2.5% to 3.5%
7	Duke Energy Florida	FL	May. 4	2021		9.85%	Duke Energy	Yes	Jun 2021: $2.5B, 10Yr, 20Yr, 30Yr at 2.5% to 3.5%
8	Pacificorp	WY	May. 18	2021		9.50%	Berkshire Hathaway	Private	Jul. 7, 2021: 1 Bil., 30 Yr. @ 2.9%
9	Potomac Electric Power	DC	Jun. 23	2021		9.28%	Exelon	Yes	Sep. 28, 2021:$125M, 30 Yr. at 3.29%
10	El Paso Electric	NM	Jun. 23	2021		9.00%	JP Mrgn Chase TII Fund	Private	
11	Potomac Electric Power	MD	Jun. 28	2021		9.55%	Exelon	Yes	Sep. 28, 2021:$125M, 30 Yr. at 3.29%
12	Kentucky Utilities	KY	Jun. 30	2021		9.43%	PPL	Yes	
13	Louisville Gas & Electric	KY	Jun. 30	2021		9.43%	PPL	Yes	
14	Atlantic City Electric	NJ	Jul. 14	2021		9.60%	Exelon	Yes	Sep. 28, 2021:$125M, 30 Yr. at 3.29%
15	Sharyland Utilities	TX	Jul.15	2021		9.38%	Sempra/Hunt Family	Private	
16	Dominion Energy S. C.	SC	Jul. 21	2021		9.50%	Dominion Energy	Yes	Aug. 11, 2021: 1B, 10 Yr., 2.25%
17	Delmarva Power & Lgt.	DE	Aug. 5	2021		9.60%	Exelon	Yes	Sep. 28, 2021:$125M, 30 Yr. at 3.29%
18	Northern States Power	ND	Aug. 18	2021		9.50%	Xcel Energy	Yes	Oct. 2021: $800M, 6 & 10 Yr. at 1.75% to 2.35%
19	Green Mtn. Power	VT	Aug. 31	2021		8.57%	Northern N.E. Energy	Private	
20	Avista	ID	Sep. 1	2021		9.40%	Avista	Yes	Sep. 28, 2021:$70M, 30 Yr. at 2.9%
21	Avista	WA	Sep. 17	2021		9.40%	Avista	Yes	Sep. 28, 2021:$70M, 30 Yr. at 2.9%
22	Tampa Electric	FL	Oct. 21	2021		9.95%	Emera	Foreign	
23	Versant Power	ME	Oct. 28	2021		9.35%	Emera	Foreign	
24	Arizona Public Service	AZ	Nov. 2	2021		8.70%	Pinnacle West	Yes	
25	Otter Tail	MN	Nov. 4	2021		9.48%	Otter Tail	Yes	
26	Ohio Power	OH	Nov. 17	2021		9.70%	Amer. Elec. Power	Yes	Jan. 4, 2022: $805M, 2 Yr. @ 2 %
27	Central Hudson Electric	NY	Nov. 18	2021		9.00%	Fortis	Yes	
28	Southwestern	TX	Nov. 18	2021		9.25%	Amer. Elec. Power	Yes	Jan. 4, 2022: $805M, 2 Yr. @ 2 %
29	Virginia Electric	VA	Nov. 18	2021		9.35%	Dominion Energy	Yes	
30	Madison Gas & Electric	WI	Nov. 23	2021		9.80%	MGE	Yes	
31	Entergy Arkansas	AR	Dec. 7	2021		9.65%	Entergy	Yes	
32	Rockland Electric	NJ	Dec. 15	2021		9.60%	Consolidated Edison	Yes	
33	Consumers Power	MI	Dec. 22	2021		9.90%	CMS Energy	Yes	
34	Public Service Co. Oklahoma	OK	Dec. 18	2021		9.40%	Amer. Elec. Power	Yes	Jan. 4, 2022: $805M, 2 Yr. @ 2 %
35	Average 2021 ROE Awarded under 10%					**9.44%**			

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-20836
Exhibit AG-1.32
May 19, 2022

Electric Rate Case Return on Equity (ROE) Rates (2020 and 2021)*

Summary of All Cases (incl. 10% and Over)

Line	Caption/No. of Cases			2020	2021	Note
1	**Number of ROE Decisions Under 10%**			37	31	Pgs 1 & 2
2	**ROEs Awarded at 10% or Higher**					
	State	Company	ROE			
3	Iowa	Interstate Pwr. & Lgt.	**10.02%**	1		A
4	Wisconsin	Wisconsin Pwr. & Lgt.	**10.00%**	1		A
5	Wisconsin	Wisconsin Pwr. & Lgt.	**10.00%**		1	A
6	Wisconsin	Northern States Pwr.	**10.00%**		1	A
7	Florida	Florida Pwr. & Lgt.	**10.60%**		1	B
8	California	PacifiCorp	**10.00%**	1		C
9	California	Liberty Utilities	**10.00%**	1	-	C
10	Total Cases with ROEs Stated (Excl. Lmtd. Issue Riders)			**41**	**34**	
11	**Avg. ROE Rate Awarded**	**Excluding 10% Plus Cases**		**9.32%**	**9.44%**	
12		**All Cases**		**9.39%**	**9.51%**	D

A In general, Iowa and Wisconsin are outliers in the move to reduce authorized ROEs

B Multi-year rate plan for 2022 to 2025 with specified limited rate increases.

C Wildfire Risk: Some California companies have been financially ravaged by wildfire damages causing substantial write-offs of uninsured excess damages and which has forced Pacific Gas & Electric into bankruptcy.

C All ROE data for this page has been obtained from Regulatory Research Associates

D Excludes Limited Issue Rider Cases

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-20836
Exhibit AG-1.33
May 19, 2022

Comparison of AG and DTEE Peer Groups

			Elimination Factors										
		2020	Revs. Over	Under			Reorg.	EPS	Nuc. Build OS Wind		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	$ 6,320			Yes		Yes				2		
2	Consolidated Edison	12,246										x	
3	Dominion Energy	14,147										x	x
4	Duke Energy	23,868	Yes								1		x
5	Eversource Energy	8,904							Yes		1		
6	Exelon	33,039	Yes								1		x
7	FirstEnergy	10,790			Yes						1		
8	NextEra Energy	17,997						Yes			1		x
9	PPL Corp.	7,607			Yes		Yes	Yes			3		
10	Public Service Enterp. Group	9,603					Yes	Yes			2		x
11	Southern Co.	20,375	Yes						Yes		2		x
12	ALLETE	1,169										x	x
13	Alliant Energy	3,416										x	x
14	Ameren	5,794										x	x
15	American Electric Power	14,918					Yes				1		x
16	CMS Energy	6,680										x	x
17	CenterPoint Energy	7,418						Yes			1		x
18	DTE Energy	12,177								Yes	1		
19	Entergy	10,114					Yes				1		x
20	Fortis	8,995				Yes					1		
21	Evergy	4,913										x	x
22	MGE Energy	539		Yes							1		x
23	OGE Energy	2,122					Yes				1		x
24	Otter Tail	890		Yes							1		x
25	WEC Energy	7,242										x	x
26	Avista	1,321										x	x
27	Black Hills	1,696										x	x
28	Edison International	13,578							Yes		1		x
29	Hawaiian Electric	2,579						Yes			1		x
30	IDACORP	1,351										x	x
31	Northwestern	1,199						Yes			1		x
32	PNM Resources	1,523					Yes				1		
33	Pinnacle West Capital	3,587						Yes			1		x
34	Portland General Electric	2,145										x	
35	Sempra Energy	11,370				Yes					1		x
36	Xcel Energy	11,526										x	x
37	Unitil	419		Yes							1		
	Totals		3	3	3	2	7	7	3	1	**29**	**13**	**30**

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-20836**
DTE Electric - Electric Rate Case | **Exhibit AG-1.33**
May 19, 2022

Companies Eliminated from Peer Group Consideration
(due to M & A, Reorg. and EPS Growth Concerns)

Line	Company involved in M & A, Reorg.*	Anticipated Actions to be Taken per Value Line
1	American Electric Power	Selling Kentucky Power for $1.5 billion
2	Avangrid	Looking to merge with PNM Resources
3	Entergy	Selling its non-regulated energy units (incl. Palisades in Mi.)
4	OGE Energy	Looking to sell its stake in Energy Transfer for $0.9 billion
5	PNM Resources	Looking to merge with Avangrid
6	PPL	Buying Naragansette Electric for $3.8 billion
7	Public Services Enterprise Group	Selling its non-regulated fossil fuel generating units for $2.5 billion

		Value Line EPS Information**			
	Company with Earnings Disruption*	2020	2021	2022	Comments based on Value Line
8	CenterPoint	$ 1.29	$ 0.94		EPS recovers to $1.25 per share by 2022
9	Hawaiian Electric		$ 2.25	$ 2.10	EPS recovers to $2.50 per share by 2026-a weak grower
10	Nextera	$ 2.10	$ 1.81		Mark to Market Charges - Earnings Volatility
11	Northwestern		$ 3.60	$ 3.30	Common Shares Increasing; EPS at $4.00 in 2026
12	Pinnacle West		$ 5.47	$ 3.95	Unfavorable rate order w/ROE at 8.7%; EPS to $5.50 in 2026
13	PPL	$ 2.04	$ 0.60		Impairment; EPS recovers to $1.80 per share by 2026
14	Public Services Enterprise Group	$ 3.61	$ 2.30		EPS recovers to $3.60 per share by 2022

* All of these companies have been included in the Company's peer group except for PPL, Avangrid and PNM Resources
** Value Line's adjusted EPS to exclude non recurring items from 2020 and 2021.

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-20836**
DTE Electric - Electric Rate Case **Exhibit AG-1.34**
Peer Group Market to Book Equity Ratios-Dec. 31, 2021 **May 19, 2022**

Line	Company (a)	Ticker (b)	Mkt. Val. p/Sh. Of Com. Equity Dec. 31, 2021* (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	Allete	ALE	$ 66.35	$ 2,413	53.2	$ 45.36	1.46
2	Alliant Energy	LNT	61.47	5,990	250.5	23.91	2.57
3	Ameren	AEE	89.01	9,700	257.7	37.64	2.36
4	Avista	AVA	42.49	2,155	71.5	30.14	1.41
5	Black Hills	BKH	70.57	2,787	64.8	43.01	1.64
6	Consolidated Edison	ED	85.32	20,037	354.1	56.59	1.51
7	CMS Energy	CMS	65.05	6,407	289.8	22.11	2.94
8	Dominion Energy	D	78.56	27,308	810.0	33.71	2.33
9	Evergy	EVRG	68.61	9,244	229.3	40.31	1.70
10	IDACORP	IDA	113.31	2,668	50.5	52.83	2.14
11	Portland General Electric	POR	52.92	2,707	89.4	30.28	1.75
12	WEC Energy	WEC	97.07	10,913	315.4	34.60	2.81
13	Xcel Energy	XEL	97.07	15,612	544.0	28.70	3.38
15	**Average**						**2.15**

* Per Yahoo
** Per SEC Filings on Form 10-K for year ended December 2021

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-20836
Exhibit AG-1.35
May 19, 2022

Rating Agency Cash Flow Ratios
(With ROE at 9.5% and a 50% Common Equity Ratio)

		2020 Adjusted Moody's Cash Flow Ratio ($ Millions)			
		Cash From Operations		Ratio	
Line	Caption	Pre-Wkg. Cap.	Debt	(e) / (f)	Note
	(a)	(b)	(c)	(d)	
1	**2020 Actual Ratio Results**	$ 2,051	$ 9,154	**22.4%**	1
2	Increase Common Equity (to 50% vs 47.7%)	-	(333)		2
3	Reduce ROE (to 9.5% vs 10.8%)	(90)			3
4	**Pro Forma w/50% Common Equity, 9.5% ROE**	$ 1,961	$ 8,821	**22.2%**	L 1 + L 2 + L 3
5	**Ratings Downgrade Risk**			***Below 20%***	4

Notes

1 From page 2 of Moody's May 18, 2021 report on DTE Electric (see AGDE 2.36-02 Attachment)

2 As noted below under "Avg. 2020 Capitalization" below, the Company's Common Equity was 47.7% in 2020. Adjusting to 50% shifts $332 million to common equity from long-term debt (2.3% x $14.5 billion = $332 million).

3

Target Net Income in Cash From Operations ($7.245 billion rebalanced equity below x 9.5% ROE level)	$ 688	M	
Actual Net Income in Cash From Operations (per page 65 of DTE 2021 Form 10-K)	778	M	
Change in Cash Flows from Operations due to lower ROE of 9.5%	$ (90)	M	**To Line 3 Above**

4 From page 2 of Moody's May 18, 2021 report on DTE Electric under "Factors that could lead to a downgrade"

Average 2020 Capitalization ($ Millions)	**Actual 2020**		**Rebalancing**	**2020 Rebalanced**	
(from Ex. A-4, Sched D1)	**Amount**	**% Capital**	**Adjustmts.**	**Amount**	**% Capital**
Long-Term Debt	$ 7,577	52.3%	$ (332)	$ 7,245	50.0%
Preferred Stock	-	0.0%		-	0.0%
Common Equity	6,913	47.7%	332	7,245	50.0%
Total	$ 14,490	100.0%		$ 14,490	100.0%

VLFAlert

ValueLine*funds*

4th Quarter 2018

Volume VII, Issue IV

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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.

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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
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Small Cap Opportunities Fund
Hybrid Funds
Asset Allocation Fund
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Tax Exempt Fund
Core Bond Fund

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-5.160a
Respondent:	M. Leuker
	1 of 1

Question: Refer to page 15, lines 12-19 of Mr. Leuker's direct testimony. Please:
a. Identify what consumer mobility data you utilized and explain why this data is reliable.

Answer: The Company utilized consumer mobility data from Google's COVID-19 Community Mobility Reports. These Community Mobility Reports aim to provide insights into what has changed in response to policies aimed at combating COVID-19.

The data is collected from aggregated, anonymized sets of data from users who have turned on Location History on the cellular devices. Google reports that over a billion people use Google Maps every month, providing further confidence that the sample utilized is sufficient for forecasting. Google also states that if there is not enough data to confidently and anonymously estimate the changes in consumer mobility, they will not report the data.

Attachment: *None*

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-5.160b
Respondent:	M. Leuker
	1 of 1

Question: Refer to page 15, lines 12-19 of Mr. Leuker's direct testimony. Please:
b. Identify what changes in consumer behavior you utilized and explain why this data is reliable.

Answer: The Company utilized the following consumer behavior patterns provided by Google:

1. Residential: Mobility trends for places of residence. Measured as the change in average duration spent in places of residence.
2. Workplace: Mobility trends for places of work. Measured as the change in total visitors.
3. Retail & Recreation: Mobility trends for places like restaurants, cafes, shopping centers, theme parks, museums, libraries, and movie theaters. Measured as the change in total visitors.

Please refer to response AGDE-5.160a for why the Company believes the data is reliable.

Attachment: *None*

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-5.161a
Respondent:	M. Leuker
	1 of 1

Question: Refer to page 15, lines 21-23 of Mr. Leuker's direct testimony.
a. What specific variables did you calculate and based on which data?

Answer: The variables calculated are class-level percent deviations from business as usual, referred to as a "wedge" in Q21 of my direct testimony. The wedge calculations utilize class-level daily AMI data, which are used in a regression model along with calendar binaries, weather variables and mobility data (from Google) to predict sales.

Attachment: *None*

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-5.161b
Respondent:	M. Leuker
	1 of 1

Question: Refer to page 15, lines 21-23 of Mr. Leuker's direct testimony.
b. Provide the calculations in Excel with formulas intact showing how you calculated the variables and wedge adjustments.

Answer: Please see attachment U-20836 AGDE-5.161b Wedge Input Data and Calculation for the Actual & Forecast data, and baseline data used to calculate the wedge. The regression models utilized to calculate the Actual & Forecast data, and baseline data are performed in proprietary software.

Attachment: *U-20836 AGDE-5.161b Wedge Input Data and Calculation*

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-5.161c
Respondent:	M. Leuker
	1 of 1

Question: Refer to page 15, lines 21-23 of Mr. Leuker's direct testimony.
c. How did you determine that the Google and IHME data was accurate and pertinent to electric sales during that time period? Did you perform any back period testing to validate the reliability of your theory, model, and the resulting adjustments?

Answer: The load forecast is foundationally built on econometric regression modeling. The primary goal of regression modeling is to theorize and quantify explanatory variables that may affect the way in which customers use electricity differently between hours, days, months, and years.

The COVID-19 pandemic policy response created an instantaneous change in the way people consume electricity. It was the intuition of the Company, and load forecasting groups across the country, that as more people stayed home, it would increase Residential electricity consumption. Conversely, as less people attended in-person work, Commercial and Industrial electricity consumption would decrease.

The step to quantifying this intuition was to utilize the Google Mobility data that measured the magnitude of these changed behaviors from COVID-19 related mitigation strategies. The mobility data was used as a dependent variable in the daily class-level tracking models where it proved to be statistically significant, as seen through the T-Statistics and P-Values of the mobility variable in each class's regression model. Additionally, the Residential model used for this case yield's an out of sample mean absolute percent error (MAPE) of 0.5% for six months of data in 2021. When removing the Wedge, driven by mobility data from the model, the out of sample MAPE is 6.27% further solidifying its validity in predicting electricity sales. Please refer to attachment U-20836 AGDE-5.161c Mobility Data Test Statistics for class-level statistics regarding the impact of mobility data on the regression models.

Attachment: *U-20836 AGDE-5.161c Mobility Data Test Statistics*

MICHIGAN PUBLIC SERVICE COMMISSION | **Exhibit AG-1.38**
DTE Electric Company | **Case No. U-20836**
Date: May 19. 2022

Incremental Revenue from Higher Residential Sales for Forecasted Test Year | **Page 1 of 1**

Line #				
1	Average Sales per Customer - 2021 [1]		7,916.1	kWh
2				
3	EWR Sales Reductions 2022 @ 1.5%	1.50% [2]	-118.7	kWh
4	EWR Sales Reductions 2023 @ 1.5%	1.25% 10 months [3]	-97.5	kWh
5				
6	Adjusted Average Sales per Customer for Projected Test Year [4]		7,699.9	kWh
7				
8	Forecasted Test Yeat average number of customers [5]		2,059,058	
9				
10	AG Forecasted Test Year Sales Before Adjustments (Line 6 x Line 8)		15,854,616,349	kWh
11				
12	Sales Adjustments:for Projected Test Year: [6]			
13	DG		(16,360,000)	kWh
14	EV		72,180,000	kWh
15				
16	AG Forecasted Test Year Sales After Adjustements (Lines 10 through 14)		15,910,436,349	kWh
17				
18	DTEE Forecasted Test Year Sales [7]		15,114,000,000	kWh
19				
20	Increase in Sales (Line 16 - Line 18)		796,436,349	kWh
21				
22	Current Distribution Rate per kWh [8]		$ 0.066110	
23				
24	**Incremental Revenue**	(Line 20 x Line 22)	**$ 52,652,407**	

Source:
(1) Exhibit AG-1.39
(2) Line 1 x 1.5%.
(3) Line 1 - Line 3 x 1.25%.
(4) Total of Lines 1 through 4..
(5) Exhibit AG-1.39
(6) DTEE response to AGDE-5.162a.
(7) Exhibit AG-1.39
(8) Exhibit A-16 , Schedule F-3, page 2, line 18.

MICHIGAN PUBLIC SERVICE COMMISSION | **Exhibit AG-1.39**
DTE Electric Company | **Case No. U-20836**
Date: May 19, 2022
Residential Sales Analysis: 2016 to 2023 and Projected Test Year | **Page 1 of 1**

	Residential [1]		Average Use		Growth
Year	W/N Sales GWh	Customers	Per Customer kWh	Change Over Prior Year	Rate
2016A	15,182	1,966,675	7,719.6		
2017A	14,979	1,980,151	7,564.8	-2.0%	
2018A	14,935	1,991,879	7,497.9	-0.9%	
2019A	14,820	2,003,542	7,396.9	-1.3%	-1.4% 3 -Year
2020A	15,947	2,019,744	7,895.4	6.7%	
2021A	16,122	2,036,578	7,916.1	0.3%	**0.5%** 5 -Year
2022F	15,326	2,048,950	7,480.1	-5.5%	
2023F	15,124	2,061,026	7,338.2	-1.9%	
PTY	15,114	2,059,058	7,340.1	-7.3%	

Source: (1) DTEE Response AGDE-1.8

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

O & M Summary-Millions of Dollars

Case No. U-20836
Exhibit AG-1.40
May 19, 2022

Line	Caption or Discription of Item (a)	Amount (b)	Reference (c)
1	**Total O & M Per Company Case**	$ 1,280.7	Ex. A-13, Sch. C5
	AG Case Adjustments		
2	Distribution Operations	$ (1.2)	Testimony
3	Tree Trimming Surge Savings	(5.7)	EX. AG-1.42
4	Customer Service	(9.7)	Testimony
5	Uncollectibles	(9.4)	Ex. AG-1.44
6	Merchant Fees	(8.2)	Ex. AG-1.45
7	Active Health Care	(9.5)	Ex. AG-1.47
8	Pension Expense		
9	Adjust for actual 2021 Results & Discount Rate	(12.0)	Note 1 & Testimony
10	Adjust Return on Assets from 6.7% to 7.0%	(5.4)	Note 2 & Testimony
11	Incentive Comp.-Remove 100% Financial related and 50% Non Financial Expense	(51.0)	Testimony
12	Total Adjustments	**(112.1)**	
13	**Total O & M per AG Case**	**$ 1,168.6**	L1 + L12

Note 1 See Discovery response AGDE-8.270 Attachment showing pension expense revised for actual 2021 performance and the actual year end end 2021 discount rate. Original amount in this case was $9.2 million vs. revised amount at minus $2.8 million (lines 13 and 45)

Note 2 See Discovery response AGDE-8.270 Attachment on lines 49 to 61 which shows the changes covered in note 2 above plus the impact of increasing the expected return rate from 6.7% to 7.0%.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-2.47a
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer Exhibit A-13, Schedule C5.6, page 1. Please:

a. Provide a schedule showing how the $3.687 million Distribution O&M expense increase in footnote 4 was derived. Provide a breakdown of the amount for "training" and "miscellaneous," and identify what is in miscellaneous.

Answer: The table below provides the breakdown of the one-time cost reductions.

Savings Initiatives	Avoided O&M (000s)	
Redeploy 35 FTEs to other areas of business	$	1,213
Delay/Cancel Training (apprentice/Smith in-person/Injury prevention)	$	1,189
Eliminate non-essential travel, in-person team events and associated expenses	$	405
Due to only essential work being performed to limit person to person contact, lower volume of materials was being used	$	270
Reduce non-electrical contractor spend (facilities/landscaping)	$	610
TOTAL	**$**	**3,687**

Attachment: None.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-7.198a
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the response to AGDE-2.47a (Exhibit A-13, Schedule C5.6, page 1). In its response, the Company shows that $1.2 million of the expense increase resulted from the redeployment of 35 FTEs to other areas of the business. Please answer the following.

a. Identify into which areas the 35 FTEs were redeployed by area and the related portion of the expense. Was this a permanent shift of resources or only for 2020?

Answer: In response to AGDE-2.47 the table of Savings Initiatives shows that the redeployment of 35 FTEs to other areas of business resulted in an avoided O&M savings of $1,213,000, not an expense increase.

Answering in terms of avoided O&M, not expense increase as asked, the shift of the 35 FTEs came from DO substation operations, and those employees were redeployed to support Customer Service. The shift was only for a part of 2020, not permanent.

Attachment: N/A

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company - Electric Rate Case

Case No. U-20836
Exhibit AG-1.42
Date: May 19, 2022

Tree Trimming Surge Savings
(Millions of Dollars)

Line	Caption or Expense Item	2020	2021	2022	2023	Test Year	Savings Test Yr. vs. 2020
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Tree Trim Reactive	$ 16.7	$ 19.0	$ 16.2	$ 15.0	$ 15.2	$ 1.5
2	Tree Trim Storm	15.9	15.0	15.0	13.2	13.5	2.4
3	Dist. Ops. Storm & Trouble	12.0	11.3	11.3	10.0	10.2	1.8
4	Total	**$ 44.6**	**$ 45.3**	**$ 42.5**	**$ 38.2**	**$ 38.9**	**$ 5.7**
5	**O & M Reduction (Equals L 4)**						**$ 5.7**

Col. (b) Hartwick testimony page 36 in Table 11 under "Current Cost".
Col. (d) AGDE-8.261
Col. (e) AGDE-8.261
Col. (f) 10/12 of 2023 and 2/12 of 2022 refelcting the Test Year ending October 2023
Col. (g) Cost Savings: Col. (b) less Col. (f).

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-2.49a
Respondent:	J. Sparks
	1 of 1

Question: Refer to Exhibit A-13, Schedule C5.7. With regard to the $1.8 million adjustment in footnote 2 related to deferred hiring, please:

a. Explain how the work completed in 2020 was accomplished if hiring was deferred.

Answer: Hiring was deferred for 2020, however the company was not working under normal business conditions (e.g. reduced non-emergency field work, halted/reduced disconnects) all of which reduced call volumes to a manageable level with a reduced staff.

Attachment: None

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-2.50a
Respondent:	J. Sparks
	1 of 1

Question: Refer to Footnote 4 in Exhibit A-13, Schedule C5.7, which shows a $7.9 million increase for "Customer Experience" and "Time of Use." On page 25 (line 3) of his testimony, witness Sparks states that this cost increase is a function of a "120 headcount" increase. Please:

a. Provide actual headcount levels at year end 2019, 2020, 2021, and as of February 28, 2022, and forecasted at the end of 2022 and 2023.

Answer: The total headcount increase is higher than the 120 requested in projected test year due to a plan to insource more calls versus outsourcing. No O&M has been requested for this change. See attachment for support to response.

Attachment: U-20836 AGDG-2.50 a and b Contact Center Headcount

DTE Electric Company									Case No:	U-20836			
Contact Center									Question	AGDE-50.a & 50.b			
Headcount									Witness	J. Sparks			
	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2022</u>	<u>2023 (1)</u>							
	Actual	Actual	Actual	As of 2/28/22	Forecast	Forecast							
Non-Rep. Support	95	123	127	134	162	162							
Call Rep.	433	444	573	674	703	610							
Total	528	567	700	808	865	772							
													2023
Monthly Forecast	**<u>Jan-22</u>**	**<u>Feb-22</u>**	**<u>Mar-22</u>**	**<u>Apr-22</u>**	**<u>May-22</u>**	**<u>Jun-22</u>**	**<u>Jul-22</u>**	**<u>Aug-22</u>**	**<u>Sep-22</u>**	**<u>Oct-22</u>**	**<u>Nov-22</u>**	**<u>Dec-22</u>**	**<u>Target (2)</u>**
Call Rep.	567	609	671	645	706	764	734	792	825	793	762	732	
Hire	64	86		86	86		86	64					
Attrition	(22)	(24)	(26)	(25)	(28)	(30)	(29)	(31)	(32)	(31)	(30)	(29)	
SubTotal Non-Rep	609	671	645	706	764	734	792	825	793	762	732	703	610
Monthly Forecast	**<u>Jan-22</u>**	**<u>Feb-22</u>**	**<u>Mar-22</u>**	**<u>Apr-22</u>**	**<u>May-22</u>**	**<u>Jun-22</u>**	**<u>Jul-22</u>**	**<u>Aug-22</u>**	**<u>Sep-22</u>**	**<u>Oct-22</u>**	**<u>Nov-22</u>**	**<u>Dec-22</u>**	**<u>2023 Avg</u>**
Non-Rep. Support	162	162	162	162	162	162	162	162	162	162	162	162	162

(1) Total heacount increase is higher than the 120 requested in projected test year due to a plan to insource more calls vs. outsourcing. No O&M has been requested for this change as the labor will be offset by vendor spend.

(2) 2023 monthly timing of hiring classes will be dependant on ongoing attrition and performance

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-3.73
Respondent:	T. Uzenski
	1 of 1

Question: Provide the number of employees, and contractors supplementing Company employees, at the end of each year 2016 to 2023 by function or department. Explain reasons for increases in headcount of 5% or greater in each function/department in 2021, 2022, and 2023 over the prior year.

Answer: See attached file.

Attachment: *U-20836 AGDE-3.73 Employees and Contractors 2016-2023.pdf*

DTEE response to AGDE-3.73

Michigan Public Service Commission
DTE Electric Company

Case No.:	U-20836
Audit Request:	AGDE-3.73
Date of Request:	3/23/2022
Respondent:	T. M.
Page:	1 of 1

Steam, Hydraulic	2016	2017	2018	2019	2020	2021	2022	2023
Employees	1,544	1,477	1,464	1,378	1,282	1,185	1,183	1,120
Contractors	121	119	87	78	54	54	54	54
Total	**1,665**	**1,596**	**1,551**	**1,456**	**1,336**	**1,239**	**1,237**	**1,174**
YoY Change						**-7.3%**	**-0.2%**	**-5.1%**
Nuclear Power								
Employees	821	927	915	866	857	820	857	857
Contractors	147	33	29	26	34	48	44	44
Total	**968**	**960**	**944**	**892**	**891**	**868**	**901**	**901**
YoY Change						**-2.6%**	**3.8%**	**0.0%**
Distribution								
Employees	2,013	2,092	2,253	2,415	2,422	2,431	2,617	2,665
Contractors	38	61	52	68	68	71	71	71
Total	**2,051**	**2,153**	**2,305**	**2,483**	**2,490**	**2,502**	**2,688**	**2,736**
YoY Change						**0.5%**	**7.4% (1)**	**1.8%**
Marketing								
Employees	105	118	123	116	123	132	138	138
Contractors	6	7	5	6	5	2	1	1
Total	**111**	**125**	**128**	**122**	**128**	**134**	**139**	**139**
YoY Change						**4.7%**	**3.7%**	**0.0%**
Customer Service								
Employees	833	931	934	976	1,013	1,154	1,163	1,163
Contractors	93	81	100	61	140	180	180	149
Total	**926**	**1,012**	**1,034**	**1,037**	**1,153**	**1,334**	**1,343**	**1,312**
Electric Equivalent FTEs	**602**	**656**	**672**	**675**	**744**	**861**	**867**	**847**
YoY Change						**15.7% (2)**	**0.7%**	**-2.3%**
Corporate Staff Group								
Employees	1,984	1,982	1,963	1,935	1,894	1,827	2,057	2,057
Contractors	703	531	585	765	692	895	842	827
Total	**2,687**	**2,513**	**2,548**	**2,700**	**2,586**	**2,722**	**2,899**	**2,884**
Electric Equivalent FTEs	**1,784**	**1,746**	**1,816**	**1,909**	**1,752**	**1,844**	**1,964**	**1,954**
YoY Change						**5.3% (3)**	**6.5% (4)**	**-0.5%**
Total w/o CSG	5,397	5,490	5,600	5,628	5,589	5,604	5,832	5,797
Total	7,181	7,236	7,416	7,537	7,341	7,448	7,796	7,751

(1) Headcount additions to support additional capital investment
(2) Additional Customer Representatives and required support for improved Customer
More resources will lead to calls being answered faster and allow for the service levels
measured daily, resulting in a better, more consistent customer experience.
(3) Higher IT headcount due to additional Customer Service IT capital spend
(4) Higher IT headcount (74) for strategic workplan to support increased Capital spend.
Remainder for 2022 is related to backfill of positions delayed in 2020 and 2021.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company - Electric Rate Case

Case No. U-20836
Exhibit AG-1.44
Date: May 19, 2022

Uncollectible Accounts Expense

Line	Caption or Description	Net Write-Off Amounts	Net Sales	% Charged Off & AG Projection (b) / (c)
	(a)	(b)	(c)	(d)
1	Year			
2	2015	$ 52,792,827	$ 4,600,768,732	
3	2016	$ 51,243,388	$ 4,940,615,302	
4	2017	$ 49,685,132	$ 4,792,185,844	
5	2018	$ 63,324,304	$ 5,029,033,833	
6	2019	$ 71,792,927	$ 4,935,971,016	
7	2020	$ 49,726,424	$ 5,215,244,507	
8	2021	$ 40,044,005	$ 5,522,666,038	
	AG Analysis:			
9	Total Year 2017*	$ 49,685,132	$ 4,792,185,844	**1.04%**
10	Total Year 2020*	49,726,424	5,215,244,507	**0.95%**
11	Total Year 2021	40,044,005	5,522,666,038	**0.73%**
12	Avg. Percentage			**0.91%**
13	Projected Test Year Revenues ($000) **			**$ 5,556,620**
14	**Total Uncollectibles per AG Estimate ($000)**		Line 12 x Line13	**50,294**
15	**Uncollectibles per DTE Gas (Ex A-13, Sch. C1, Line 8) ($000)**		Ex. A-13, Sch. C5.8, col. (g)	**59,673**
16	***Reduction in O & M Expense for Uncollectibles ($000)***		Line 14 less Line 15	***$ (9,379)***

Source: DR AGDE 2.53a Attchmt.

Notes:

* The years 2018 and 2019 are omitted here due to problems in 2018 with the Customer 360 System impacting Uncollectible Accounts expense in 2018 and net write offs in 2018 and 2019. See Coppola direct testimony.

** From Company Exhibit A-16, Schedule F2, page 2 of 4, Line 47 which includes 100% of the DTE Electric Proposed Rate Increase.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company - Electric Rate Case

Case No. U-20836
Exhibit AG-1.45
Date: May 19, 2022

Residential Mechant Fees
(Millions of Dollars)

Line	Caption	Actual Data Provided by Company*						Notes
		2016	**2017**	**2018**	**2019**	**2020**	**2021**	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Historic Cost Information							
1	Total Electric Residential Revenues	$ 2,477	$ 2,310	$ 2,494	$ 2,427	$ 2,825	$ 2,926	
2	Electric Residential Revenues Paid by Credit/Debit Card	664	709	809	876	1,057	1,162	
3	% Electric Revenues Paid by Credit/Debit	26.81%	30.69%	32.44%	36.09%	37.42%	39.71%	L2 / L1
4	Avg. Percentage Increase Per Year			*2.58%*	*over 5 Yrs.*			
5	Historic Residential Merchant Fees	$ 4.2	$ 4.9	$ 5.8	$ 7.0	$ 9.4	$ 9.9	
6	Electric Residential Revenues Paid by Credit/Debit Card	664	709	809	876	1,057	1,162	
7	Percentage of Revenues Paid in Merch. Fees	0.63%	0.69%	0.72%	0.80%	0.89%	0.85%	L5 / L6

Line	Caption	Test Year Projection Per AG	Test Year Projection Per DTEE	O & M Reduction**	Notes for Col. (d) Calc.
8	Projected Test Year Residential Revenues	$ 2,893			Note 1
9	Percentage to be Paid by Debit/Credit Cards	44.44%			Note 2
10	Revenues Subject to Fees	1,286			L8 X L9
11	Percentage of Revenues Paid in Merch. Fees	0.85%			Note 3
12	**Residential Merchant Fees and O & M Adjustment**	$ 10.9	$ 19.1	**$ (8.2)**	L8 X L9

Notes
1 Test year Revenues from Exhibit A-16, Sched. F2, page 2, line 11.
2 Line 3 percentage of 39.71% increased by 2.58% per year (from line 4) equals 44.44%
3 Reflects the most recent experience for 2019, 2020 and 2021 as indicated in line 7 above
* All of this data in lines 1, 2, 5 and 6 provided by the Company (see Ex. AG-1.46, AGDE 2.52b)
** AG Projection less DTEE Projection

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-2.52a
Respondent:	B. Burns
	1 of 1

Question: Refer to Exhibit A-13, Schedule C5.7.1. Please:

a. Expand this exhibit to include actual information for 2016, 2017, and 2021 and provide in Excel.

Answer: Please reference attached document for response.

Attachment: U-20836 AGDE-2.52a Merchant Fee Actuals

Michigan Public Service Commision
DTE Electric Company
($ Mil)

Case No: U-20836
ADGE-2.52a
3/21/2022
Respondent: B. Burns

Line No.	Description	2016	2017	2018	2019	2020	2021
1	**Merchant Fees**						
2	Merchant Fees Residential	$ 4,167	$ 4,883	$ 5,751	$ 6,992	$ 9,437	$ 9,946
3	Merchant Fees Non-Residential	2,053	3,248	4,705	5,427	4,240	3,911
4	**Total Merchant Fees**	$ 6,220	$ 8,131	$ 10,456	$ 12,418	$ 13,677	$ 13,857

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-2.52b
Respondent:	B. Burns
	1 of 1

Question: Refer to Exhibit A-13, Schedule C5.7.1. Please:

b. Provide a schedule showing (a) total residential revenues for each of the five years ending in 2021; (b) the residential customer payments received through credit and debit cards for each of those years; and (c) the applicable merchant fees for each of those years. Provide this information in Excel.

Answer: Please reference attached document for response.

Attachment: U-20836 AGDE-2.52b Residential Revenue, Payments and Merchant Fees

Michigan Public Service Commision
DTE Electric Company
($ Mil)

Case No: U-20836
ADGE-2.52b
3/21/2022
Respondent: B. Burns

		2016	2017	2018	2019	2020	2021
A.	Electric Residential Revenue	$ 2,477.2	$ 2,309.6	$ 2,493.8	$ 2,426.9	$ 2,825.4	$ 2,925.9
	Total Residential Payments from Credit/Debit Cards	$ 999.9	$ 1,073.9	$ 1,227.1	$ 1,347.9	$ 1,594.5	$ 1,755.5
	Electric Allocation	*66.44%*	*66.00%*	*65.94%*	*65.00%*	*66.29%*	*66.23%*
B.	Electric Residential Payments from Credit/Debit Card	$ 664.3	$ 708.8	$ 809.2	$ 876.1	$ 1,057.0	$ 1,162.7
C.	Electric Residential Merchant Fees	$ 4.2	$ 4.9	$ 5.8	$ 7.0	$ 9.4	$ 9.9

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company - Electric Rate Case

Case No. U-20836
Exhibit AG-1.47
Date: May 19, 2022

Medical Expenses -Reduced Inflation Rate
(Thousands of Dollars)

Line	Caption	2016	2017	2018	2019	2020	Normalized 2020-2021	
		Actual Gross Expenses						
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Historic Cost Information							
1	Gross Actual Medical, Dental & Vision	$ 63,573	$ 69,195	$ 68,182	$ 70,419	$ 67,201	$ 74,189	Note 1
2	Average Employees	6,401	6,582	6,795	6,896	6,848	6,848	Note 2
3	Cost per Employee (L1 / L2)	$ 9.932	$ 10.513	$ 10.034	$ 10.212	$ 9.813	$ 10.834	
4	Avg. Annualized Cost per Employee Increase			***2.50%***				

Line	Caption	Normalized 2020	2021	2022	2023	Test Year*	
			Projected Normalized Expense				
	Projected Cost Information						
5	Normalized 2020 Escalated 2.5% per Year	74,189	76,043	77,944	79,893	79,568	Note 3
6	Less Allocation to Costs Capitalized at 39%	(28,934)	(29,657)	(30,398)	(31,158)	(31,032)	Note 4
7	Net Cost in O & M	$ 45,255	$ 46,386	$ 47,546	$ 48,735	$ 48,537	Line 5 less Line 6
							Original
8	Company Expense Estimate					$ 58,019	Ex. A-13, Sch. C5.11, pg. 1 (L11)
9	***Reduction in Medical Expense and O & M***					***$ (9,482)***	Line 7 less Line 8

Notes
1 Line 1, Col. (b) to (f) are from AGDE 2.62 Attachment. Line 1, Col. (g) is the average of 2020 actual less COVID costs ($67.2 M less $3.1M COVID costs=$64.1 M) and 2021 actual costs of $84.3 M -- reflects many elective and other proceedures deferred from 2020 to 2021 due to COVID-19 pandemic.
2 From Exhibit A-13, Schedule C5.11.1 Rev. line 5
3 The 2.5% escalation per year is based upon the historical 2016 to 2020 historical experience from line 4 above
4 Reflects 39% allocated to costs capitalized leaving 61% allocated to O & M on Line 7 (Based on 2021 actual results-see AGDE 2.62).
* Lines 5 and 6 in this column reflect 10/12 of 2023 costs and 2/12 of 2022 costs since the test year is 12 months ended Ocotober 2023.

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.263b
Respondent:	M. Cooper
	1 of 1

Question: Refer to page 7, lines 1-18 of Mr. Cooper's direct testimony. Please:
b. Explain why the Company is increasing the fixed income allocation for the projected increase in funded status. Provide the asset mix between debt, equity, and other investments of the assets for each year 2019 to 2021 and projected for 2022 and 2023.

Answer: Pursuant to the Company's Liability Driven Investment strategy (LDI), the Company decreases its exposure to equity market volatility by increasing the proportion of fixed income investments as the pension funding status increases.

The actual asset mix at year end 2019 through 2021 and the target asset mix for the years 2022 through 2023 are reflected in the table below.

	Actual Year End Investment Mix			Target Asset Mix	
Category	**2019**	**2020**	**2021**	**2022**	**2023**
Equity	35.1%	39.1%	28.9%	33%	31%
Alternative	22.5%	23.6%	23.9%	25%	24%
Fixed Income	42.5%	37.3%	47.3%	42%	45%
	100.0%	100.0%	100.0%	100%	100%

Attachment: None

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.263c
Respondent:	M. Cooper
	1 of 1

Question: Refer to page 7, lines 1-18 of Mr. Cooper's direct testimony. Please:
c. Provide the actual returns for the plan assets for each year 2010 to 2021.

Answer: The actual annual return based on beginning of year pension plan assets are reflected in the table below. Year to date March 31, 2022, the actual return on assets net of fees was a negative 7.1%.

Year	Actual Return on Beginning Asset Balance
2010	12.3%
2011	(0.9%)
2012	11.3%
2013	14.3%
2014	8.0%
2015	(2.0%)
2016	6.6%
2017	17.1%
2018	(5.1%)
2019	20.8%
2020	16.5%
2021	8.4%

Attachment: None

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-8.270
Respondent:	M. Cooper
	1 of 1

Question: Refer to Exhibit A-13, Schedule C5.12.2. Please provide the same information based on the actual asset return in 2021 and an ERoA of 7% in 2022 and future years. Based on this run, provide the same information shown in Exhibit A-13, Schedule C5.12.1 for lines 11-17 in Column (d).

Answer: Please see the update of Exhibit A-13, Schedule C5.12.2 in the attachment entitled "U-20836 AGDE-8.270 Pension Scenarios Update", which reflects the actual return on assets in 2021 of 8.4%, the actual discount rate as of December 31, 2021, of 2.91% and the expected return on assets for 2022 and 2023 of 7.0%. This schedule includes the adjustments for the pension costs capitalized and transferred consistent with the presentation on Exhibit A-13, Schedule C5.12.1.

Attachment: U-20836 AGDE-8.270 Pension Scenarios Update

DTE Electric Company
Case No. U-20836
AGDE-8.270
Pension Cost Scenarios Update
($000)

Line No.	Description	2021	2022	2023	12 mos Ending 10/31/2023
	(a)	(b)	(c)	(d)	(e)
		Base Projection			
1	Service Costs	81,037	77,180	73,815	74,376
2					
3	Interest Costs	117,090	115,362	113,481	113,795
4	Expected Return on Assets	(243,002)	(251,082)	(258,342)	(257,132)
5	Amortizations				
6	(Gain)/Loss	138,376	101,344	80,070	83,616
7	Prior Service Costs	(1,175)	(1,179)	(1,179)	(1,179)
8	Financing Costs	11,289	(35,555)	(65,970)	(60,901)
9	Total	92,326	41,625	7,845	13,475
10	Transfers	(455)	(370)	(453)	(439)
11	Capitalization - Service Costs only	(29,277)	(27,853)	(26,604)	(26,813)
12	Capitalization - Non-Service Costs to Reg Asset	(4,250)	13,340	24,838	22,922
13	Net Expense	58,344	26,742	5,625	9,145
14					
15		**2021 Actual Asset Return of 8.4%**			
16					
17	Service Costs	81,037	77,180	73,815	74,376
18					
19	Interest Costs	117,090	115,362	113,481	113,795
20	Expected Return on Assets	(243,002)	(248,504)	(257,300)	(255,834)
21	Amortizations				
22	(Gain)/Loss	138,376	99,855	73,606	77,981
23	Prior Service Costs	(1,175)	(1,179)	(1,179)	(1,179)
24	Financing Costs	11,289	(34,466)	(71,392)	(65,237)
25	Total	92,326	42,714	2,423	9,139
26	Transfers	(455)	(379)	(428)	(417)
27	Capitalization - Service Costs only	(29,277)	(27,853)	(26,604)	(26,813)
28	Capitalization - Non-Service Costs to Reg Asset	(4,249)	12,931	26,880	24,554
29	Net Expense	58,344	27,413	2,271	6,463
30					
31		**Actual Discount Rate at 12/31/21 of 2.91%**			
32					
33	Service Costs	81,037	72,810	69,635	70,164
34					
35	Interest Costs	117,090	124,927	122,949	123,278
36	Expected Return on Assets	(243,002)	(252,520)	(261,211)	(259,763)
37	Amortizations				
38	(Gain)/Loss	138,376	82,253	57,551	61,668
39	Prior Service Costs	(1,175)	(1,179)	(1,179)	(1,179)
40	Financing Costs	11,289	(46,519)	(81,891)	(75,995)
41	Total	92,326	26,291	(12,255)	(5,831)
42	Transfers	(455)	(233)	(335)	(319)
43	Capitalization - Service Costs only	(29,277)	(26,276)	(25,098)	(25,294)
44	Capitalization - Non-Service Costs to Reg Asset	(4,249)	17,453	30,833	28,603
45	Net Expense	58,344	17,235	(6,856)	(2,842)
46					
47		**ERoA of 7.0 % in 2022 and 2023**			
48					
49	Service Costs	81,037	72,810	69,635	70,164
50					
51	Interest Costs	117,090	123,405	121,521	121,835
52	Expected Return on Assets	(243,002)	(255,797)	(269,090)	(266,875)
53	Amortizations				
54	(Gain)/Loss	138,376	81,627	57,358	61,403
55	Prior Service Costs	(1,175)	(1,179)	(1,179)	(1,179)
56	Financing Costs	11,289	(51,944)	(91,390)	(84,816)
57	Total	92,326	20,866	(21,754)	(14,651)
58	Transfers	(455)	(184)	(290)	(274)
59	Capitalization - Service Costs only	(29,277)	(26,276)	(25,098)	(25,294)
60	Capitalization - Non-Service Costs to Reg Asset	(4,250)	19,488	34,409	31,923
61	Net Expense	58,344	13,894	(12,734)	(8,297)

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company - Electric Rate Case

Operating AIP and REP Performance Measure Results: 2017 - 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Line		**AIP**						**REP**						**Combined**
No	**Description**	**2017**	**2018**	**2019**	**2020**	**2021**	**Average**	**2017**	**2018**	**2019**	**2020**	**2021**	**Average**	**Average**
1	**DTE Electric**													
2	Less than Threshold	2	5	4	3	4		2	5	4	3	4		
3	Between Threshold and Target	1	2	3	0	2		1	2	3	0	2		
4	Target	1	0	0	1	0		1	0	0	1	0		
5	Between Target and Maximum	6	3	4	6	3		4	2	2	5	2		
6	Maximum	4	4	2	4	0		4	4	2	4	0		
7		14	14	13	14	9		12	13	11	13	8		
8														
9	**Nuclear Generation**													
10	Less than Threshold	0	1	3	1	2		0	1	3	1	2		
11	Between Threshold and Target	1	1	0	1	3		1	1	0	0	2		
12	Target	1	1	0	1	0		1	1	0	1	0		
13	Between Target and Maximum	2	2	3	1	1		1	1	1	1	1		
14	Maximum	4	2	2	3	1		3	2	2	3	1		
15		8	7	8	7	7		6	6	6	6	6		
16														
17														
18	**DTE LLC**													
19	Less than Threshold	2	5	5	5	3		2	5	5	5	3		
20	Between Threshold and Target	1	2	3	0	1		1	2	3	0	1		
21	Target	1	0	0	1	0		1	0	0	1	0		
22	Between Target and Maximum	5	3	5	6	4		4	2	4	5	3		
23	Maximum	5	4	5	5	0		4	4	4	5	0		
24		14	14	18	17	8		12	13	16	16	7		
25														
26	**Total**													
27	Less than Threshold	4	11	12	9	9		4	11	12	9	9		
28	Between Threshold and Target	3	5	6	1	6		3	5	6	0	5		
29	Target	3	1	0	3	0		3	1	0	3	0		
30	Between Target and Maximum	13	8	12	13	8		9	5	7	11	6		
31	Maximum	13	10	9	12	1		11	10	8	12	1		
32		36	35	39	38	24		30	32	33	35	21		
33														
34	**Measures at Target and Above**													
35	Target	3	1	0	3	0		3	1	0	3	0		
36	Between Target and Maximum	13	8	12	13	8		9	5	7	11	6		
37	Maximum	13	10	9	12	1		11	10	8	12	1		
38	Total Measures at Target and Above	29	19	21	28	9		23	16	15	26	7		
39														
40	Total Measures	36	35	39	38	24		30	32	33	35	21		
41														
42	**Percentage of Measures at Target and Above**	80.6%	54.3%	53.8%	73.7%	37.5%	**60.0%**	76.7%	50.0%	45.5%	74.3%	33.3%	**55.9%**	**58.0%**

Source: DR: AGDE-8.272

MICHIGAN PUBLIC SERVICE COMMISSION **Revised Exhibit: AG-1.50**
DTE Electric Company **Case No: U-20836**
May 19, 2022
Calculation of Return on Regulatory Asset Balance for Tree Trimming Surge Costs **Page 1 of 1**

Line No.	Description	Test Period Amount	Reference
1	**Return on Tree Trim Regulatory Asset**		Exhibit A-11, Schedule A1.1
2	Average Balance Regulatory Asset	108,160	
3	Deferred Tax Liability	(28,013)	
4	Average Net Rate Base	80,147	
5	Short-term Interest Rate	1.74%	Exhibit A-14 D1
6	Return on Tree Trim	$ 1,395	

Computation of Revenue Deficiency for Projected Test Year November 2022 to October 2023

($000)

Line	Description	Company Filed Amount	AG Recommended Adjustments	Revised Amount
	(a)	(b)	(c)	(d)
1	Rate Base [1]	$ 21,267,944	$ (679,932)	$20,588,012
2	Rate of Return	5.56%	-0.30%	5.26%
3	Income Required	$ 1,181,647	$ (98,718)	$ 1,082,929
4	Adjusted Net Operating Income [2]	899,199	140,456	1,039,655
5	Income Deficiency (Sufficiency)	$ 282,448	$ (239,174)	$ 43,274
6	Revenue Multiplier	1.3496	1.3496	1.3496
7	**Revenue Deficiency (Sufficiency)**	381,201	$ (322,797)	58,404
8	Revenue Deficiency - Tree Trim Surge Program	7,021	(5,626)	1,395
9	**Revenue Deficiency (Sufficiency) - Total**	**$ 388,222**	**$ (328,423)**	**$ 59,799**

(1) Rate Base Adjustments Exhibit AG-1.26

(2) AG adjustments to Operating Income - Increase (Decrease):

			Source
Sales Revenue		$ 52,652	Exh. AG-1.38
O&M Expenses		112,100	Exhibit AG-1.40
Depreciation Expense		28,003	Exhibit AG-1.26
Total		$ 192,755	
Effective Tax Rate (1-1/1.3496)	25.91%		
Taxes		(49,935)	
Interest Synchronization on Capital Adjustments		(2,364)	RevDef-WP1
Adjusted Net Operating Income		$ 140,456	

(3) AG Calculation of Tree Trim Surge Program at Short-term Debt rate $ 1,395 Exhibit AG-1.50

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend its	)	Case No. U-20836
rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
DAVID E. DISMUKES, Ph.D.

May 19, 2022

TABLE OF CONTENTS

MICHIGAN DEPARTMENT OF THE ATTORNEY GENERAL

QUALIFICATIONS AND DIRECT TESTIMONY OF DAVID E. DISMUKES, Ph.D.

Line No.

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. ON WHOSE BEHALF DO YOU TESTIFY IN THIS PROCEEDING?

A. I am testifying on behalf of the Michigan Department of the Attorney General ("AG").

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University ("LSU"). I am also a full Professor in the Department of Environmental Sciences and the Director of the Coastal Marine Institute in the School of the Coast and Environment at LSU. In addition to my appointment at LSU, I also serve as a Senior Fellow at the Institute of Public Utilities

("IPU") at the Michigan State University ("MSU") where I regularly teach courses on utility regulation and other energy topics. Appendix A provides my academic curriculum vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided expert testified before the Commission in Case No. U-14893, a general rate case filing for SEMCO Energy Gas Company, Case No. U-20471, DTE Electric Company's ("DTE" or "Company") Integrated Resource Plan filing, Case No. U-20561, DTE's last electric rate case filing, and Case Nos. U-20697 and U-20963, the Consumers Energy Company's ("Consumers") last two electric rate case proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the AG to provide an expert opinion to the Michigan Public Service Commission ("Commission") on issues related to DTE's proposed class cost of service study ("CCOSS"), its proposed revenue distribution, and other rate design issues.

Q. HAS YOUR TESTIMONY BEEN PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have prepared ten exhibits in support of my direct testimony that were prepared by me or under my direct supervision. They are labeled exhibits AG-2.1 through AG-2.10, inclusive.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Peer Utility Retail Rate Comparison
- Section IV: Class Cost of Service Study
- Section V: Revenue Distribution
- Section VI: Conclusions and Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE ALLOCATION OF COSTS ASSOCIATED WITH PRODUCTION PLANT FACILITIES?

A. I recommend that the Commission modify the weighting of the existing 4 CP 75-0-25 cost allocation method to one that equally weights demand and energy concerns, or a 4 CP 55-0-45 cost allocation methodology. My proposed 4 CP 55-0-45 cost allocation method is based on my analysis of what would constitute a fair and reasonable approximation of the relative cost of service. Specifically, my proposed 4 CP 55-0-45 would make the cost allocation of the Company's production plant consistent with recent system load factors for DTE over the last five years (2017 through 2021), which have consistently ranged between 44.4 and 48.1 percent. Furthermore, my recommendation would make the cost allocation consistent with examinations of the relative classification of individual Company generation units.

Q. WHY DO YOU FEEL THAT THE COMMISSION SHOULD REASSESS ITS POLICY WITH REGARD TO THE APPROPRIATE ALLOCATION OF COSTS ASSOCIATED WITH PRODUCTION PLANT FACILITIES?

A. The current requested rate increase represents the eighth such rate increase in the past 15 years. These rate increases have consistently assigned a disproportionate percentage of the applicable rate increase to residential customers. The consistent, significant rate increases to residential customers have led to the Company having notably uncompetitive residential rates when compared to other regional and national electric utilities. Indeed, this is demonstrated by the Company's own benchmarking analysis, which found that DTE both has the highest residential electric rates in the region, and that these rates have been growing at a faster rate than its regional peers.[1]

Q. WHAT IS YOUR RECOMMENDATION FOR AN APPROPRIATE ALLOCATION OF SECONDARY-VOLTAGE DISTRIBUTION SYSTEMS?

A. I recommend that the Commission allocate costs associated with demand-related secondary-voltage distribution systems based on class Non-Coincident Peak ("NCP") demands. The Company's proposed allocation places too much emphasis on individual customer peak loads, and fails to recognize that not all customers present peak demands on the system peak at the same time. Furthermore, allocating secondary-voltage distribution costs in a manner consistent with the allocation of primary-voltage distribution costs is consistent with how these costs are typically allocated in other jurisdictions.

Q. WHAT IS YOUR RECOMMENDED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a revenue distribution that reflects my alternative CCOSS recommendations. Ultimate revenue distribution effects of these changes will depend on the Commission's adopted revenue requirement for the Company. However, based on the Company's proposed revenue requirement, the

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[1] *See*, Exhibit AG-2.3 at 4.

changes discussed earlier would result in the residential customer class receiving a 6.19 percent increase in rates. Additionally, secondary customers would receive a 10.48 percent increase in rates, while primary customers would receive a 6.69 percent increase in rates.

Q. HAVE YOU PREPARED ANY EXHIBITS THAT PROVIDE EXPLANATORY RATES USING YOUR PROPOSED ALTERNATIVE CCOSS RECOMMENDATIONS AND REVENUE DISTRIBUTION?

A. Yes. Exhibit AG-2.9 presents an explanatory comparison of the resulting rates based on my proposed alternative CCOSS recommendations at the Company's proposed revenue requirement to both current and Company proposed rates.

III. <u>PEER UTILITY RETAIL RATE COMPARISON</u>

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED RATE INCREASE.

A. The Company is requesting to increase its rates by $388 million for the 12-month period beginning November 1, 2022.[2] If awarded, rates will increase by an average of 7.5 percent on a system-wide basis and by 8.8 percent for the residential class alone. Further, this proceeding represents the eighth time the Company has requested a rate increase since 2007.

Q. HAVE YOU EXAMINED THE HISTORICAL TREND IN THE COMPANY'S RATES?

A. Yes. Exhibit AG-2.1 shows the Company's rate increase trends since Case No. U-15244 in 2008. The Company has seen its annual revenues increase by $524.2 million,

[2] Application at ¶9.

or by 11.3 percent over a 14-year period.[3] Importantly, these increases have not been spread equally across the Company's various customer classes.

Q. WHAT HAVE THESE INCREASES MEANT FOR RESIDENTIAL RATEPAYERS?

A. These historic rate increases have disproportionately impacted residential and other smaller usage customer classes relative to primary-voltage and high load factor customer classes. Residential revenues alone have increased by 46.7 percent since Case No. U-15244. Revenues from primary-voltage customers, on the other hand, have decreased by 26.4 percent over the same period. These trends will only continue if the Company's proposals are accepted in full by the Commission in this proceeding. The Company's proposed 8.8 percent increase to residential rates is larger than any other increase being proposed for any other non-lighting customer class in this proceeding.

Q. HOW DO THE COMPANY'S RATES COMPARE TO OTHER REGIONAL UTILITIES?

A. In Case No. U-20162, Natural Resources Defense Council ("NRDC"), Michigan Environmental Council ("MEC"), Sierra Club ("SC"), Energy Innovation Business Council ("EIBC") and Institute for Energy Innovation ("IEI") argued that residential rates in Michigan, and particularly DTE's residential rates, were high compared to other states,[4] and that this is likely due to the Company allocating too much of its generation costs based on contribution to system peak and too little of these costs based on energy contribution.[5] This over-emphasis on customer load factors discounts rates for industrial

[3] This represents the difference between the total test year revenues in the current proceeding of $5.179 billion compared to total test year revenues of $4.655 billion in Case No. U-15244.
[4] MPSC Case No. U-20162, Direct Testimony of Douglas B. Jester at 41:13-19.
[5] *Id.,* at 44:18-19.

customer classes at residential customer classes' expense, as will be explained later in this testimony. In the Company's prior rate case, Case No. U-20561, MEC, NRDC, SC, and Citizens Utility Board of Michigan ("CUB"), revisited the issue of the lack of competitiveness of the Company's residential rates, reiterating that DTE's residential rates were unusually high relative to rates for industrial customers when compared against other electric utilities.[6]

Q. DOES THE COMPANY ROUTINELY REVIEW ITS RATES RELATIVE TO OTHER ELECTRIC DISTRIBUTION COMPANIES?

A. Yes. The Company prepares a benchmarking study each spring and fall that compares its rates and bills to other states using data reported by the Department of Energy, Energy Information Administration ("EIA").[7] Exhibits AG-2.2 and AG-2.3 present the Company's Spring 2019 and Spring 2021 benchmarking studies in their entirety. These studies show that the Company's rates compare poorly to other Michigan and Midwestern utilities. The analysis also shows that the Company's residential retail rates are particularly uncompetitive relative to regional peers.

Q. WHAT DOES THE COMPANY'S 2021 RATE COMPARISON ANALYSIS SHOW?

A. The Company's residential rates are 31 percent higher than the average U.S. residential rate and 28 percent higher than the average of other Great Lakes States.[8] Indeed, the Company has some of the highest residential rates in the country, exceeding the state-wide average of all states in the continental U.S, excluding California and some

[6] *Id.,* at 30:10-12.
[7] *Id.*, Company's Response to Data Request AGDE-2.50.
[8] Company's Response to Data Request AGDE-1.13, Attachment U-20836 AGDE-1.13 Spring 2021 Rate Benchmarking.pdf at 9.

states in the Northeast.[9] In its regional peer analysis, the Company found that its residential rates are not only high, but have the highest five-year rate of growth in the region.[10] The Company's residential rates have increased by 7.5 percent between 2019 and 2020, and by 3.5 percent per year over the past five years. This is compared to the average increase among other Great Lakes utilities, which have seen only 0.7 percent growth in residential rates between 2019 and 2020, and 0.8 percent growth per year over the past five years.[11]

Q. WHAT DOES THE COMPANY'S ANALYSIS SHOW REGARDING ITS INDUSTRIAL RATES IN 2020?

A. The Company's industrial rate comparison shows that DTE's industrial rates are lower than the average of other Michigan utilities.[12] Indeed, the Company's analysis finds that its industrial rates are reasonably competitive outside of Michigan, being lower than similar rates for industrial customers in nearby Wisconsin and only five percent greater than the average of all Great Lakes and U.S. utility averages.[13]

Q. WHY HAS THE COMPANY'S RATE COMPETITIVENESS IMPROVED FOR INDUSTRIAL CUSTOMERS RELATIVE TO OTHER CUSTOMER CLASSES?

A. This is largely a function of the historic changes in the Company's CCOSS methods. As will be discussed in greater detail later, Section 11 of Act 286 took effect after January 1, 2009,[14] and changed production plant cost allocation methods starting with Case No. 15645 in November 2009.[15] Section 11 of Act 286 also required the

[9] Id.
[10] *Id.*, at 4.
[11] Id.
[12] *Id.*, at 12.
[13] *Id.*, at 11.
[14] 2008 PA 286 § 11(1).
[15] MPSC Case No. U-15645 *et al.*; Order at 69-72.

Commission to adopt cost-of-service based rates. These new cost allocation methods resulted in more costs being allocated to residential customers relative to higher load factor customers. The methodology adopted as a result of Act 286 was subsequently changed by the Commission in Case No. U-17688 in 2015 in order to "better recognize the value of capacity in Consumers' system."[16] This new cost allocation method was adopted beginning with Case No. 17735 in that same year,[17] an action later given some legislative support through Act 341 of 2016.[18]

IV. COST OF SERVICE STUDY

A. Introduction

Q. WHAT IS THE PURPOSE OF A CLASS COST OF SERVICE STUDY OR CCOSS?

A. A "CCOSS" is a method by which utility costs and revenues are reconciled across different customer classes. The goal of a CCOSS is to determine the cost of providing service to an individual customer class and the revenue contribution each class makes to cover those costs. The results of these studies produce a rate of return and revenue requirement. The rate of return and revenue requirement can be used as a tool in developing the relative revenue responsibility and rates for each rate class within a specific jurisdiction.

Q. HOW IS A CCOSS PREPARED?

A. Typically, a CCOSS is prepared by defining a set of cost information, and then (1) "functionalizing" the cost information; (2) "classifying" the cost information; and (3)

[16] MPSC Case No. U-17688; Opinion and Order at 17.
[17] MPSC Case No. U-17735; Order at 96-98.
[18] 2016 PA 341 § 11(1).

"allocating" the cost information. The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e., production, transmission, and distribution). The next step of the process "classifies" each of these respective costs into a unique "type" of cost, including those that are either demand-related, commodity-related, or customer-related. The last step of the process "allocates" each of these costs to a respective jurisdiction or customer class as appropriate.

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY DEMAND-RELATED COSTS?

A. Yes. Demand-related costs are associated with meeting maximum energy demands. Electric substations and line transformers at the distribution level are designed, in part, to meet the maximum customer demand requirements. The most common demand allocation factors used in a CCOSS are those related to system coincident peaks ("CP") or NCP.

Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

A. Energy-related costs are defined as those that tend to change with the amount of electricity (i.e., kWh) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electricity sales.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while other costs are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what are known as “joint and common” costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize. Therefore, unique allocation factors are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations.

Q. HOW DOES A CCOSS RELATE TO ECONOMIC PRINCIPLES?

A. A CCOSS is also referred to as a “fully allocated cost study” since it allocates test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the CCOSS is to estimate the cost responsibility for various customer classes, which in turn are used to develop rates. At the core of a CCOSS is a set of historic book costs for a utility that have accumulated over decades. Rates are, therefore, based upon historic average costs; whereas economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, regulated utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with a number of joint and common costs, difficult. This problem is exacerbated by the fact that the cost information utilized in a CCOSS is usually historic and static, not dynamic and forward-looking. These analytic deficiencies undermine many experts’ cost causation/pricing claims. As a result, in regular practice there is no single correct answer that is revealed in a CCOSS. It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the CCOSS, and the implications both have in setting fair, just, and reasonable rates. This is one of the reasons why many regulators use CCOSS results as a “guide” in setting rates and are not bound by their results.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS COSS METHODOLOGIES?

A. The CCOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two activities are dedicated to determining how much revenue will be recovered through rates, the CCOSS process determines *how* those costs (revenue requirements) will be recovered through customer rates. The primary controversy with the evaluation of various CCOSS results often rests with determining whether costs (revenue requirements) will be recovered by the relative customer share of each class, the peak load contributions of each customer class, or whether and how the approach will be tempered through the use of customer, peak, and off-peak usage considerations. Methodologies that are heavily skewed toward customer and peak considerations, for instance, can tend to shift costs more than proportionally to relatively lower load-factor customers, such as residential and small commercial customers. These approaches can also fail to capture the service being provided by the utility (*i.e.*, electric service in this case), and how the value of that service varies by the amount purchased by different customer classes.

B. Overview of DTE’s CCOSS

Q. WHAT IS THE PURPOSE OF THE COMPANY’S PROPOSED CCOSS?

A. The Company states that the objective of its CCOSS is to apportion all costs required to serve customers among each customer class in a fair and equitable manner, defined as a manner which best reflects the engineering and operating characteristics of the electric utility system.[19] To accomplish this, the Company functionalized all costs in the cost study as either power supply (combining the elements of the traditional production and transmission functions) or distribution.[20]

Q. PLEASE DESCRIBE THE DEMAND ALLOCATORS USED WITHIN THE COMPANY'S CCOSS.

A. The Company uses a variety of demand allocators within its CCOSS to allocate different classified costs. To allocate production plant costs classified as demand-related, the Company uses what it refers to as a "4CP 75-0-25" cost allocation method.[21] This is a hybrid allocation factor that is based upon a combination of two separate component calculations through a weighted average. The first component of this hybrid allocation factor is based on an examination of each rate class's contribution to the Company's average four monthly coincident peaks ("4CP") and this average receives a 75 percent weight. The second component of this hybrid allocation factor uses each rate class's contribution to the Company's annual energy requirement and receives a 25 percent weight.[22] To allocate transmission plant costs classified as demand-related, the Company uses what it refers to as a "12CP 100-0-0" cost allocation method, which is based on an examination of each rate class's contribution to the Company's average twelve monthly CP ("12CP").[23] For lower-voltage transmission facilities classified as demand-related, the Company uses each rate class's relative NCP demand to allocate

[19] Direct Testimony of Habeeb J. Maroun at 5:16-20.
[20] Id., at 5:24-25.
[21] *Id.,* at 9:3-8.
[22] *Id.,* at 9:3-8.
[23] *Id.,* at 9:8-12.

costs associated with sub-transmission and primary-voltage distribution facilities.[24] The Company uses several separate allocation factors calculated using this generalized approach, accounting for different class loss factors and class uses at different voltage levels on the Company's system.[25] Lastly, the Company uses a summation of each individual customer maximum demand within a rate class to allocate secondary-voltage distribution facilities costs classified as demand-related.[26]

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED CCOSS?

A. Yes. I disagree with the use of several of the Company's CCOSS cost allocation methods, including the: (1) classification of production plant; (2) the sub-transmission plant demand allocator; and (3) the secondary-voltage distribution demand allocation based on a summation of each individual customer maximum demand.

C. Allocation of Production Plant

Q. PLEASE DESCRIBE THE COMPANY'S 4CP 75-0-25 PRODUCTION PLANT COST ALLOCATOR.

A. The Company's production plant cost allocation method uses the hybrid demand allocator approach I discussed earlier, which is a weighted average of each rate class's contribution to the average four monthly CP ("4CP") and each rate class's contribution to the Company's annual energy requirement.[27] The weights are 75 percent (CP component) and 25 percent (energy component) and were administratively set in 2015

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[24] See, Direct Testimony of Maheen Ashgar, Exhibit A-17.
[25] For example, sub-transmission rate classes are not assigned any portion of distribution-specific costs, while primary voltage distribution rate classes are not assigned any portion of secondary-specific distribution costs as these customers bypass these systems. For a general diagram of the Company's system operations, see Direct Testimony of Habeeb J. Maroun, Exhibit A-16.
[26] See, Direct Testimony of Maheen Ashgar, Exhibit A-17.
[27] Direct Testimony of Habeeb J. Maroun at 9:3-8.

by Commission Order in Case No. U-17689.[28] Prior to this Order, the Company had utilized a 12CP 50-25-25 cost allocation methodology as outlined by the Legislature in Public Act 286 of 2008 (hereafter, "Act 286").

Q. PLEASE DESCRIBE ACT 286.

A. Act 286 was part of a package of bills that passed the Michigan Legislature in late 2008, in the midst of the 2008-2009 financial crisis and recession.[29] Act 286 has been described as a "smorgasbord" of changes to then-existing utility laws generally designed to increase the financial strength of the state's electric utility companies to allow for easier attraction of capital to support upgrades to existing infrastructure.[30] One of the components of the Act was the restoration of electric utilities' traditional monopoly status as exclusive provider of electricity to customers located in their defined jurisdiction.[31] However, the Act also established a Certificate of Necessity ("CON") process[32] and established a pre-approval process for mergers and acquisitions of utilities operating in the state,[33] among other changes. Included in these changes was Section 11, often referred to as the "de-skewing" provision,[34] which required the Commission to phase in cost-of-service based rates over a five-year period.[35]

Q. WHAT MOTIVATED SECTION 11 OF ACT 286?

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[28] MPSC Case No. U-17689; Opinion and Order (June 15, 2015).
[29] 2008 PA 286.
[30] Babcock, Lisa and Rodger Kershner (January 2011), Changes in the Law Governing Public Utilities, Michigan Bar Journal, January 2011:35.
[31] 2008 PA 286 § 10f.
[32] 2008 PA 286 § 6s.
[33] 2008 PA 286 § 6q.
[34] Babcock, Lisa and Rodger Kershner (January 2011), Changes in the Law Governing Public Utilities, Michigan Bar Journal, January 2011:40.
[35] 2008 PA 286 § 11.

A. Some observers have noted that the motivation arose, in part, from the frustration of many Michigan high load factor customers who believed they were overly subsidizing residential customers.[36] Section 11 of Act 286 required the Commission to move rates towards actual cost of providing service and utilize a 50-25-25 cost allocation methodology. However, Act 286 did allow the Commission to modify this prescribed cost allocation methodology, provided a greater amount of costs would not be allocated to primary service customers.[37]

Q. WHAT DID THE ACT SAY ABOUT THIS POTENTIAL DEVIATION FROM STRICT COST OF SERVICE RESULTS?

A. Act 286, section 11(1) noted

> This subsection applies beginning January 1, 2009. Except as otherwise provided in this subsection, the commission shall phase in electric rates equal to the cost of providing service to each customer class over a period of 5 years from the effective date of the amendatory act that added this section. If the commission determines that the rate impact on industrial metal melting customers will exceed the 2.5% limit in subsection (2), the commission may phase in cost-based rates for that class over a longer period. The cost of providing service to each customer class shall be based on the allocation of production-related and transmission costs based on using the 50-25-25 method of cost allocation. The commission may modify this method to better ensure rates are equal to the cost of service if this method does not result in a greater amount of production-related and transmission costs allocated to primary customers.[38]

Q. HOW IS A 50-25-25 COST ALLOCATION METHOD DEFINED?

[36] Babcock, Lisa and Rodger Kershner (January 2011), Changes in the Law Governing Public Utilities, Michigan Bar Journal, January 2011:40.
[37] 2008 PA 286 § 11(1).
[38] 2008 PA 286 § 11(1), emphasis added.

A. Act 286 did not define the 50-25-25 cost allocation method, but the Commission later accepted a Staff interpretation of the cost allocation formula defined as: (1) 12 CP demand weighted 50 percent; (2) energy use coincident to MISO on-peak periods weighted 25 percent; and (3) annual total energy use weighted 25 percent.[39] The Commission used this methodology to allocate production plant facilities until June 2015, when it approved the current 4CP 75-0-25 allocation method in Case No. U-17689.

Q. WHY DID THE COMMISSION MODIFY THE PRODUCTION PLANT COST ALLOCATION METHOD IN CASE NO. U-17689?

A. In Case No. U-17689, the Company's initial CCOSS proposal utilized a 100 percent 4 CP cost allocation methodology for classifying and allocating costs associated with production plant facilities.[40] This proposal would have changed the then-current demand measurement for production plant from 12 CP to 4 CP and would have also removed the existing energy component that was utilized in the prior allocation factor. The Company argued that such a change was warranted since it had completed the process of de-skewing rates outlined in Section 11 of Act 286, and that future expected generation shortfall in the Lower Peninsula from generation retirements warranted the requested change.[41] The Company argued that future production plant investments would be driven by the need to meet system demand requirements during its four summer peaking months.[42]

> [a 100 percent 4CP allocation] reflects the increased emphasis on production capacity, rather than energy, which is necessary due to the need for new production capacity and

[39] MPSC Case No. U-15244; Opinion and Order at 77.
[40] MPSC Case No. U-17689, Opinion and Order at 3.
[41] Id.
[42] Id., at 4.

> the investment necessary to retrofit existing generation to meet environmental standards.[43]

Q. DID STAFF AGREE WITH THE COMPANY'S COST CLASSIFICATION ASSERTIONS?

A. No. Staff disagreed with the Company's proposal in part, arguing that the Company's production system was built and operated to meet both the Company's capacity and energy requirements.[44] The Commission agreed with Staff's position, stating that the Company's system included a mix of baseload plants designed to provide low-cost energy to all customers and peaking plants designed to meet peak demands during summer months.[45] The Commission also accepted Staff's proposed 4CP 75-0-25 cost allocation methodology as more consistent with this understanding and thus better aligned with cost of service.[46]

Q. HAS THE LEGISLATURE REVISITED SECTION 11 OF ACT 286?

A. Yes. Act 286 was revisited first in Public Act 169 of 2014,[47] and then again in Public Act 431 of 2016 ("Act 431").[48] The latter notably modified Section 11 to remove the Legislature's prior-stated preference for a 12 CP 50-25-25 allocation for production-related costs, instead requiring a "75-0-25" cost allocation. Act 431 allowed the Commission to modify this cost allocation approach if it determined these approaches did not ensure appropriate cost of service-driven rates.[49] Likewise, the Legislature granted increased flexibility in setting cost of service-based rates, allowing the Commission to

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[43] Id., citing DTE Electric Initial Brief at 13.
[44] Id., at 5.
[45] Id., at 21-22.
[46] Id., at 23.
[47] 2014 PA 169 § 11.
[48] 2016 PA 431 § 11.
[49] *Id.*; note Act 431 does not define the referenced 75-0-25 cost allocation methodology.

implement rate changes over time if it determines that there is a material impact on customer rates.[50]

> Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid. If the commission determines that the impact of imposing cost of service rates on customers of an electric utility would have a material impact on customer rates, the commission may approve an order that implements those rates over a suitable number of years. The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service.[51]

Q. WHAT FUNCTIONS DO PRODUCTION FACILITIES SERVE?

A. The Commission noted in Case No. U-17689 that electric generating units ("EGUs") are designed to serve both energy and demand/capacity needs of a utility. The exact degree of this split between energy and demand functionality depends on the individual EGU in question and its place in the utility's dispatch curve. EGUs defined as baseload units serve more of the utility's energy needs, while EGUs defined as peaking units serve more of the utility's demand or capacity needs. It is, therefore, not uncommon to develop composite energy and demand allocators that represent this mixed use and classification. Hence, Staff's 4CP 75-0-25 cost allocation method from Case No. U-17689

[50] Id.
[51] Id.

has similarities with the Average and Peak ("A&P") cost allocation methodology,[52] or peak and average demand cost allocation methodology,[53] used in some other jurisdictions.

Q. PLEASE DESCRIBE AN A&P COST ALLOCATION METHODOLOGY.

A. An A&P cost allocation methodology is based upon a two-component weighted average. The first component represents each rate class's share of a utility's total annual energy sales, and the second component represents each rate class's share of a utility's annual system peak demand. These components are combined through a weighted average: in the case of the 4CP 75-0-25 allocation, 75 percent demand and 25 percent energy.

Q. DOES THE 4CP 75-0-25 ALLOCATION METHOD DEVIATE FROM COMMONLY ACCEPTED COST ALLOCATION PRACTICES?

A. Yes. While the framework of the 4CP 75-0-25 allocation adheres to commonly accepted cost allocation practices, the arbitrary 75 percent demand and 25 percent energy weighting for classifications does not. The weighting between demand and energy components should be based on the utility's system load factor, as this reflects the disposition of average and peak loads on the system. This method weights the energy component by the utility's overall system load factor, while the peak demand component is weighted by the inverse of the system load factor (*i.e.*, 1 minus the system load factor).

Q. PLEASE DEFINE WHAT IS MEANT BY A "LOAD FACTOR."

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[52] See, for example, In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service, Arkansas Public Service Commission Docket No. 13-028-U, Direct Testimony of Corey A. Pettett, 8:11-20.

[53] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners at 57-59.

A. A load factor is defined as the ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. The load factor is expressed as a percentage and may be derived by multiplying the megawatt hours in the period by 100 and dividing by the product of the maximum demand in megawatts and the number of hours in the period. A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently since usage is consistent and does not swing largely between average and peak periods. Conversely, systems with low load factors must maintain idle capacity in order to meet the relatively large swings in load between average and peak periods.

Q. HAVE OTHER PARTIES IN THE PAST ARGUED THAT DTE'S PRODUCTION COST ALLOCATOR WAS TOO HEAVILY WEIGHTED TOWARDS DEMAND INTERESTS?

A. Yes. In U-20162 (2019), parties recommended that the Commission review DTE's production cost allocation method in the Company's next rate case.[54] The Administrative Law Judge ("ALJ") agreed with this recommendation, noting that the Company had failed to rebut evidence that energy costs allocated through the Company's CCOSS are less than MISO Locational Marginal Prices ("LMP"), while allocated capacity costs are higher than estimated Cost of New Entry ("CONE").[55] The Commission also agreed with this assessment and reminded parties of its previously expressed preference for the equivalent peaker cost allocation method or something similar:[56]

> That any party proposing to revise the production cost allocation method in a future case include in its evidentiary

[54] These parties included Michigan Environmental Council ("MEC"), Natural Resources Defense Council ("NRDC"), and the Sierra Club. See, MPSC Case No. U-20162; Order at 125.
[55] In MPSC Case No. U-20162; Notice of Proposal for Decision at 228.
[56] MPSC Case No. U-20162; Order at 129.

> presentation an analysis using the equivalent peaker method or an approximation for comparison purposes. On pages 52-53 of the NARUC Manual, it states that "[e]quivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generation capacity and the most cost-effective type of capacity to be added.[57]

Q. WHAT IS THE EQUIVALENT PEAKER COST ALLOCATION METHOD?

A. The equivalent peaker cost allocation methods is a cost allocation method that seeks to determine production capacity costs based on the composition of generation facilities being allocated. In this allocation method, rate base for each operating generation facility is calculated and then classified between demand and energy classifications based on the characteristics of the generation facility. Rate base associated with peaking plants are classified as 100 percent demand-related, while rate base of other generating units are carefully proportioned between demand and energy classifications.[58]

Q. WHAT WAS THE ORIGIN OF THE COMMISSION'S EXPRESSED PREFERENCE FOR THE EQUIVALENT PEAKER OR SIMILAR COST ALLOCATION METHOD?

A. The Commission's preference can be discerned from discussion in Case No. U-18014, where the Commission was asked to accept a Company proposal to use a 100 percent demand classification for all costs associated with its production plant facilities.[59] This was the second time that the Company had made such a proposal. In the U-18014

[57] Id.
[58] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners at 52-53.
[59] MPSC Case No. U-18014; Order at 100.

proposal for decision ("PFD"), which the Commission ultimately accepted, the ALJ rejected the 100 percent classification as being unsupported when compared against the evidence presented regarding the "longstanding recognition of the importance of considering energy consumption as well as peak demand in allocating production costs."[60] The ALJ noted that the Company's defense of the 100 percent demand classification was based on repetitive arguments, and asked parties to provide a more analytical examination of the subject, particularly one examining the characteristics of the Company's generation resources, to better match costs with cost-causation.[61] It was in this context the ALJ laid out the standard the Commission later accepted.[62]

Q. DID THE COMMISSION REVISIT THE ALLOCATION OF COSTS ASSOCIATED WITH PRODUCTION PLANT FACILITIES IN THE COMPANY'S LAST GENERAL ELECTRIC RATE CASE?

A. Yes. In the PFD, the ALJ disagreed with some parties that the Commission intended that the Equivalent Peaker method, and only the Equivalent Peaker method, could be presented as an alternative to existing production plant cost allocation methods.[63] The ALJ found that an examination of the Company's system load factors sufficiently supported a modification of the existing 75-0-25 allocation to 70-0-30.[64] The Commission, however, declined to adopt the ALJ's recommendations regarding the proposed modification to the existing production plant cost allocation methodology, finding that the record evidence in U-18014 was insufficient to overcome statutory

[60] MPSC Case No. U-18014; Notice of Proposal for Decision at 273.
[61] *Id.,* at 274.
[62] *Id.,* at 274.
[63] MPSC Case No. U-20561; Notice of Proposal for Decision at 395.
[64] *Id.,* at 395-396.

requirements, though it reiterated its openness to reviewing alternative methodologies in future rate cases.[65]

Q. HAVE YOU PREPARED AN ANALYSIS OF THE COMPANY'S SYSTEM LOAD FACTORS FOR THE RECENT YEARS OF COMPANY OPERATIONS?

A. Yes. Exhibit AG-2.4 shows DTE's system load factors using 4 CP for the five-year period 2017 through 2021. As can be seen from Exhibit AG-2.4, DTE's system load factors have been stable throughout the five-year period. Specifically, DTE's system load factors have consistently been in a narrow range of between 44.4 and 48.1 percent, averaging across all five years at 46.3 percent.

Q. WHAT DO THE COMPANY'S SYSTEM LOAD FACTORS FOR THE TEST YEAR IMPLY?

A. The results of the analysis presented in Exhibit AG-2.4 imply that the current 4CP 75-0-25 cost allocation methodology is too heavily weighted towards demand considerations relative to energy when compared to the Company's actual reported data. The Commission noted in Case No. U-17689 that electric utilities develop and operate production plant facilities around both capacity and energy requirements. My finding of an average system load factor of 46.3 percent implies that the Company's system, during its all-in system peak demand events, is serving a demand wherein 46.3 percent of this demand is equivalent to annual average load requirements placed on the system and the other 53.7 percent is "peak" demand that only occurs during these peak events. In other words, during these system peak demand events, 46.3 percent of the load present are baseloads while the other 53.7 percent can be considered peak loads.

[65] MPSC Case No. U-20561; Order at 220.

Q. WHY IS THE RESULT OF CURRENT LOAD FACTOR ANALYSIS SUBSTANTIVELY DIFFERENT FROM THE FINDINGS IN CASE NO. U-20561 SUPPORTING A PROPOSED 70-0-30 COST ALLOCATION METHODOLOGY?

A. The ALJ in Case U-20561 accepted a modified analysis put forward by opposing parties in the proceeding that was inaccurate. Specifically, The Kroger Co. ("Kroger") argued that the A&P cost allocation method as promulgated by the *Electric Utility Cost Allocation Manual* published by the National Association of Regulatory Utility Commissions ("NARUC," generally "NARUC Manual") utilizes a weighting defined by the following equation:[66]

$$Energy\ Weighting = Average\ Demand\ /\ (Maximum\ Demand + Average\ Demand)$$

Q. IS THIS EQUATION PREVIOUSLY PROMULGATED BY KROGER THE SAME AS SYSTEM LOAD FACTOR?

A. No. As defined by the NARUC Manual itself, load factor is the ratio of average demand to maximum demand over a designated time period. It is not the ratio of average demand to the summation of average demand and maximum demand.

> **Load Factor.** This is the ratio of the average demand over a designated time period to the maximum demand occurring in that period. This term can refer to a customer, rate class or the total system. It is a measure of the energy consumed compared to the energy that would have been consumed if the group or customer had used power at its maximum rate established during the designated time period.[67]

Q. IS THIS CHARACTERIZATION OF LOAD FACTOR CONSISTENT WITH OTHER AUTHORITATIVE SOURCES?

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[66] MPSC Case No. U-20561; Rebuttal Testimony of Justin Bieber at 8:6-9.

[67] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, p. 168.

A. Yes. An article published in the premier American Economic Review in December 1915, similarly defines load factor as the ratio of average demand to maximum demand, consistent with the NARUC Manual's definition.

> The load factor, as defined by electrical engineers, is the ratio of average to maximum load for some specified period. More generally expressed, it is the ratio for a particular good or service of the average demand (in the sense of "demand" as used in economics) through a period of time to the greatest demand at any one time within the period.[68]
>
> (…)
>
> The term "load factor" was invented and its use has developed in connection with electrical supply. The load factor is always, either explicitly or by implication, a determining consideration in electrical rate making. The term has been rather loosely used. The authoritative definition of the Standards Committee of the American Institute of Electrical Engineers adopted by the Institute is: "The load factor of a machine, plant, or system is the ratio of the average power to the maximum power during a certain period of time."[69]

Q. DO YOU AGREE WITH THE PRIOR WEIGHTING PROPOSED BY KROGER IN THE COMPANY'S LAST ELECTRIC RATE PROCEEDING?

A. No. The incorrect weighting put forward by Kroger in the Company's last electric rate proceeding appears to incorporate the flawed argument that cost allocation methods such as the A&P allocation method double-weights the energy component of a customer's usage patterns by utilizing average demand in both the average and peak components of the calculation.[70] These arguments conflate the concepts of energy and demand and their roles in utility system planning, essentially viewing the utility's role in system planning as serving the needs of baseload customers before customers with peaker load profiles.

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[68] Watkins, G.P. (December 1915); "A Third Factor in the Variation of Productivity: The Load Factor;" *The American Economic Review,* Vol. 5, No. 4 (Dec., 1915), p. 753.
[69] *Id.*, p. 757.
[70] *See*, MPSC Case No. U-20561; Rebuttal Testimony of Justin Bieber at 8:14-17.

In reality, the demand and energy needs of a utility's customers are distinct parameters that utilities independently have to plan for.

Q. CAN YOU PROVIDE AN EXAMPLE OF THIS LOGICAL ERROR?

A. Yes. Consider a hypothetical utility system with a 100 percent load factor, or constant electrical use during every hour of the year. This hypothetical system would likely be served fully by baseload generation EGUs to minimize fuel costs, resulting in no demand component needed to be considered by the utility. An allocation regime relying on system load factor as a weighting of the energy and demand components would recognize this fact. However, the incorrect weighting regime proposed by Kroger in the Company's last rate case proceeding would still, inexplicitly, allocate 50 percent of costs associated with utility production plant assets on the basis of demand. Indeed, using the faulty weighting calculation proposed by Kroger it is mathematically impossible for these costs to ever be allocated less than 50 percent on the basis of demand, regardless of the observed use of the utility's production plant assets.

Q. HAVE YOU CONDUCTED ANY ANALYSIS OF THE RELATIVE CLASSIFICATION OF INDIVIDUAL COMPANY GENERATION UNITS?

A. Yes. Exhibit AG-2.5 presents the results of two separate analyses of the Company's EGU operations during the test year. The first analysis, presented on page 1 of Exhibit AG-2.5, examines the gross plant in service of each unit, and the unit's capacity factor during the test year to characterize the role the unit serves in the Company's dispatch of electricity. The second analysis, presented on page 2 of Exhibit AG-2.5, also examines the gross plant in service of each unit but relies on an examination of the levelized cost of each unit relative to established market analyses to classify the function the unit serves.

Q. WHAT IS THE RESULT OF YOUR FIRST ANALYSIS OF COMPANY EGU OPERATIONS?

A. My first analysis of Company EGU operations results in a 58.4 percent and 41.6 percent split between energy and capacity functions within the Company's rate base. For this analysis, I assumed that all non-renewable generation units with capacity factors below 11 percent served only demand functions on the Company's system, while units with larger capacity factors serve both energy and demand functions based on the unit's capacity factor. Renewable generation units were functionalized as 100 percent energy due to the interruptible nature of renewable generation. Therefore, units such as Fermi 2 and the Monroe power station that are dispatched during more hours of the year, and thus have higher capacity factors, are classified as serving a larger degree of energy functions relative to demand functions. Specifically, 87.9 percent of plant in service associated with Fermi 2 is classified as energy-related, while 51.2 percent of plant in service associated with Monroe is classified as energy-related, based on observed 2021 capacity factors for these facilities.

Q. WHAT IS THE RESULT OF YOUR SECOND ANALYSIS OF COMPANY EGU OPERATIONS?

A. My second analysis of Company EGU operations finds that, at most, only 50.6 percent of the Company's production plant in service could be classified as being associated with provision of demand-functions. In this second analysis, I examined the levelized annual cost for each of the Company's non-renewable EGUs compared with

CONE prices found by MISO in its most recent analysis of the 2021/2022 Planning Resource Auction ("PRA") results.[71] All costs less than the MISO CONE price were classified as being associated with provision of demand functions, while prices above the MISO CONE price were classified as being associated with the provision of energy functions. Similar to my first analysis, renewable generation units were classified as 100 percent energy-related due to the interruptible nature of the facilities. Four of DTE's coal facilities and the Fermi 2 nuclear facility were classified as serving at least some energy functions. This analysis notably does not account for carrying costs associated with capital-intensive EGUs that have depreciable lives measured in decades. Therefore, the results of this analysis should be viewed as showing the greatest percentage of demand classification of the Company's production plant that could be supported.

Q. HAVE PARTIES CRITICIZED THESE TYPES OF ANALYSES IN THE PAST?

A. Yes. It has been argued that these types of analyses assume that utilities build base load generation facilities to reduce fuel costs, a distinction that has greatly diminished with the maturity of natural-gas fired combined cycle generation facilities.[72] Second, it is argued that these analyses do not allocate the benefit of lower fuel costs provided by base load generation to high load factor customers.[73]

Q. HOW DO YOU RESPOND TO THESE CRITICISMS?

A. These criticisms of analyses of generation unit costs are flawed. First, while generation facilities are ultimately constructed to meet a utility's forecasted peak system demands, the choice of type of generation unit to pursue is driven mostly by a desire to

[71] "2021/2022 Planning Resource Auction (PRA) Results;" (April 12, 2022); MISO.
[72] *See*, MPSC Case No. U-20561; Rebuttal Testimony of James R. Dauphinais at 34:10-21.
[73] *Id.*, 35:3-21.

optimize its generation fleet at the lowest reasonable cost to its customers. This optimization is driven in large part by forecasted fuel and other variable costs. In other words, a generation system that is expected to operate for long durations will often utilize technologies that maximize the resultant energy produced relative to fuel and other variable operating costs. While it is true that the maturation of new natural gas combined cycle technologies has greatly diminished the distinction between generation technologies, this observation is largely irrelevant. Utility systems must still optimize its systems to provide sufficient capacity and generation for the lowest possible costs, even if this process is more straightforward than in previous decades.

Second, the argument that high load factor customers should be evaluated in the presence of a hypothetical fuel credit conflates the concepts of energy and demand and their roles in utility system planning. Specifically, this assumes that a utility constructs baseload generation units to serve its higher load factor customers while less efficient peaker units are relied upon to serve lower load factor customers. This is not how utilities design their generation systems and all customers, regardless of load factor, contribute to both a utility's peak capacity requirement and its annual energy requirements. It is for this reason that it is generally accepted that fuel costs should be allocated to all customers on a uniform basis with regards to energy consumption – i.e. on a uniform per-kWh basis.

Q. WHY DOES AN EXAMINATION OF THE COMPANY'S EGU OPERATIONS FIND A SIGNIFICANT PORTION OF THESE FACILITIES BEING OPERATED TO SUPPORT THE PROVISION OF NON-DEMAND FUNCTIONS?

A. Both analyses presented in Exhibit AG-2.5 examine the Company's electric generation fleet on the basis of production plant in service. Most of the Company's electric generation fleet are peaking units that are constructed to serve the capacity needs of the Company's system. However, the Company's non-peaking generation fleet comprise the majority of the Company's production plant in service. Indeed, the Monroe facility alone represents 32.9 percent of the Company's gross production plant in service. In total, 69.6 percent of the Company's production plant in service is associated with the Company's five coal facilities and the Fermi 2 nuclear facility.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE ALLOCATION OF COSTS ASSOCIATED WITH PRODUCTION PLANT FACILITIES?

A. I recommend that the Commission modify the weighting of the existing 4 CP 75-0-25 cost allocation method to one that equally weights demand and energy concerns, or a 4 CP 55-0-45 cost allocation methodology. My proposed 4 CP 55-0-45 cost allocation method is based on my analysis of what would constitute a fair and reasonable approximation of the relative cost of service. Specifically, my proposed 4 CP 55-0-45 would make the cost allocation of the Company's production plant consistent with recent system load factors for DTE over the last five years (2017 through 2021), which have consistently ranged between 44.4 and 48.1 percent. Furthermore, my recommendation would make the cost allocation consistent with examinations of the relative classification of individual Company generation units.

Q. WHY DO YOU FEEL THAT THE COMMISSION SHOULD REASSESS ITS POLICY WITH REGARDS TO THE APPROPRIATE ALLOCATION OF COSTS ASSOCIATED WITH PRODUCTION PLANT FACILITIES?

A. As I have discussed previously in this testimony, the current rate increase request represents the eighth such rate increase in the past 15 years. Furthermore, these rate increases have consistently assigned a disproportionate percentage of each increase to residential customers. These consistent, significant rate increases to residential customers have led to DTE having notably uncompetitive residential rates when compared to other regional and national electric utilities. Indeed, this is demonstrated by the Company's own benchmarking analysis which found that both had the highest residential electric rates in the region, and that these rates have been growing at a faster rate than its regional peers.[74]

D. Allocation of Secondary-Voltage Distribution Plant

Q. HOW DOES THE COMPANY PROPOSE TO ALLOCATE COSTS ASSOCIATED WITH SECONDARY-VOLTAGE DISTRIBUTION PLANT FACILITIES?

A. The Company uses an allocation methodology based on the summation of individual customer's peak demand requirements to allocate costs associated with secondary-voltage distribution plant facilities.[75] This is in contrast to how the Company allocates costs associated with other demand-related distribution plant facilities, which the Company allocates on the basis of class NCP.[76] In practice, the Company's proposed allocation of costs associated with secondary-voltage distribution plant facilities places a higher burden on lower load factor customer classes, such as residential customers, as it assumes that facilities must be designed to serve the maximum demand of each customer simultaneously, regardless of how customer load profiles compare to each other.

[74] *See*, Exhibit AG-2.3 at 4.
[75] See Direct Testimony of Maheen Ashgar, Exhibit A-17.
[76] *Id*.

Q. HOW ARE DISTRIBUTION SYSTEMS DESIGNED AND OPERATED IN THE CONTEXT OF THE LARGER ELECTRIC POWER GRID?

A. Distribution system components such as substations, feeders, and transformers are typically designed in a fashion that ensures sufficient capacity is available to meet the local area loads. However, equally important is a consideration of the load diversity present on such systems. For example, primary distribution-voltage circuits may serve some primary voltage commercial customers and a number of secondary-voltage electric circuits, thus displaying greater load diversity in end-use. Secondary-voltage electric circuits can still have a good deal of load diversity if such circuits serve customers with different load profiles, such as a retail storefront operating during daylight hours being served by a secondary-voltage circuit that also serves a residential housing community whose residents are typically home during evening hours.

Q. HOW DO DIFFERENCES IN END-USE LOAD DIVERSITY IMPACT APPROPRIATE COST ALLOCATION?

A. The design motivation of distribution system components depends on the load diversity present, with more diverse systems serving broader system-wide peak demands, and less diverse systems serving more localized peak demands. The choice of appropriate demand allocation factor should also follow this separation, with systems designed to meet broader system-wide peak demands being allocated based on allocators derived from CP measures of demand, as opposed to systems designed to meet more localized peak demands being allocated based on allocators derived from localized system demand measures such as NCP measures. The Company's use of an allocator based on the sum of individual customers' maximum demands implies a hyperundiversified system wherein secondary-voltage distribution systems serve customers' loads that effectively peak simultaneously.

Q. HAVE OTHER ELECTRIC UTILITIES CONDUCTED ANALYSES OF DIVERSITY OF LOADS PRESENT ON ELECTRIC DISTRIBUTION SYSTEMS?

A. Yes. As an example, Arizona Public Service ("APS") analyzed the load profiles of residential customers on its system and found a great deal of heterogeneity in customer load profiles even though its analysis was restricted solely to residential customers. APS assigned names to five separate generalized load profiles it identified in its analysis, such as "Weekday Evening Peakers," "Weekday Night Owls," and "Weekday Daytimers."[77] In all, APS found that "Weekday Evening Peakers" represented a plurality of residential customers on its system, but that approximately 58 percent of residential customers did not fall in this category.[78] Intuitively, "Weekday Evening Peakers" represent customers who work during the day (i.e. 9 am to 5 pm) and thus experience peak demands in the early evening when returning home. However, retirees, stay-at-home parents, and persons working evenings have load patterns different from this generalization. The presence of distributed generation systems, such as rooftop solar photovoltaic, also cannot be discounted as this has a noticeable effect on a customer's load profile.

Q. HAVE YOU RESEARCHED HOW OTHER UTILITIES HAVE ALLOCATED COSTS ASSOCIATED WITH SECONDARY-VOLTAGE DISTRIBUTION SYSTEMS?

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[77] In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return; Arizona Corporation Commission Docket No. E-01345A-16-0036; APS Rate Case Technical Conference (September 29, 2016) at 14.

[78] Id., Direct Testimony and Exhibits of Briana Kobor at 70, Table 9.

A. Yes, I have examined eighteen rate cases filed from the period 2010 to 2018. In 66.7 percent of cases, the accepted CCOSS allocated costs associated with demand-related secondary-voltage distribution plant on an identical basis to costs associated with demand-related primary-voltage distribution plant assets. Likewise, in 72.2 percent of accepted CCOSS, the allocation of secondary-voltage distribution plant was based on identified class NCP. There are a few examples of accepted CCOSS in which costs associated with secondary-voltage distribution plant assets were allocated in a manner that differed from costs associated with primary-voltage distribution plant assets. One example is Potomac Electric Power Company ("PEPCO"), which operates in the District of Columbia. However, even in this example, the accepted allocation is 50-50 weighting of class NCP and the sum of customer individual demands, compared to DTE's proposed 100 percent allocation based on the sum of customer individual demands. This recognizes that loads present on secondary-voltage distribution systems even in a highly urbanized environment present some measure of diversification.

Q. WHAT IS YOUR RECOMMENDATION FOR AN APPROPRIATE ALLOCATION OF SECONDARY-VOLTAGE DISTRIBUTION SYSTEMS?

A. I recommend that the Commission allocate costs associated with demand-related secondary-voltage distribution systems based on class NCP demands. The Company's proposed allocation places too much emphasis on individual customer peak loads failing to recognize that not all customers present on the system peak at the same time. Furthermore, allocating secondary-voltage distribution costs in a manner consistent with the allocation of primary-voltage distribution costs is consistent with how these costs are typically allocated in other jurisdictions.

E. CCOSS Recommendations

Q. PLEASE SUMMARIZE YOUR CCOSS RECOMMENDATIONS.

A. I recommend the Commission utilize a set of alternative CCOSS methodologies that include: (1) use of a 4CP 55-0-45 cost allocation method for classifying and allocating costs associated with production plant facilities; and (2) an NCP cost allocation of costs associated with secondary-distribution plant facilities.

Q. WOULD YOUR CCOSS RECOMMENDATIONS CHANGE THE CLASS RATES OF RETURN?

A. Yes. Using my recommended allocation factors, I have also prepared an explanatory alternative CCOSS, which is attached to this testimony as Exhibit AG-2.6. In this exhibit, pages 1 and 2 show the results of my alternative CCOSS as it relates to the Company's provision of power service, while pages 3 and 4 relate to the Company's provision of distribution service. It should be noted, however, that the alternative CCOSS presented in Exhibit AG-2.6 is independent of revenue requirement adjustments supported by other witnesses for the AG and is thus presented for explanatory purposes only. In addition, I have prepared Exhibit AG-2.7, which shows the results of the Company's CCOSS in this same format.

Q. WOULD THE CCOSS RECOMMENDATIONS CHANGE REQUIRED CAPACITY AND NON-CAPACITY REVENUES ASSOCIATED WITH THE PROVISION OF POWER SERVICE?

A. Yes. Exhibit AG-2.8 shows the results of the Company and my explanatory alternative CCOSS as it relates to the breakout of required capacity and non-capacity revenues associated with the provision of power service.

V. REVENUE DISTRIBUTION

A. Revenue Distribution Policy Objectives

Q. PLEASE EXPLAIN THE PURPOSE OF THE REVENUE DISTRIBUTION PROCESS IN SETTING RATES.

A. The revenue distribution process allocates a utility's overall revenue deficiency across customer classes, which in turn is used to establish a new set of retail rates. The revenue distribution process often uses the results from the CCOSS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their CCOSS-estimated class returns. The class revenue responsibilities that are finally established are then used, in conjunction with each class's billing determinants, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates.

Q. DOES THE REVENUE DISTRIBUTION PROCESS INCLUDE ANY POLICY CONSIDERATIONS?

A. Yes. Allocating the overall system-wide revenue deficiency entirely on a full cost of service basis could result in outcomes inconsistent with Commission policies, including situations leading to adverse rate impacts for certain under-earning classes. To avoid such a result, regulators often moderate the revenue responsibilities assigned to various customer classes in order to meet a broad set of ratemaking policy goals.

Q. WHAT ARE THOSE BROADER RATEMAKING POLICY GOALS?

A. There are several generally accepted rate-making principles used in utility regulation that include:

- Rates should be fair, just, and reasonable, and not unduly discriminatory.
- To the extent possible, gradualism should be used to protect customers from rate shock.
- Rate continuity should be maintained.
- Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
- Rates should be understandable to customers.[79]

Q. HOW ARE THE ABOVE PRINCIPLES APPLIED IN DEVELOPING RATES FOR A REGULATED UTILITY?

A. Regulators often consider all, or many of the principles I mentioned above. However, any principle's relative weight can change depending upon the importance of certain policy goals. The revenue distribution process, like rate design in general, should strike a balance between policy goals and result in rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates and, as a result, judgment is necessary to formulate a rate design that meets these objectives.

Q. HOW ARE THESE PRINCIPLES APPLIED IN MICHIGAN?

A. Act 341 requires that the Commission approve rates equal to the cost of providing service to each customer class.[80] This requirement is universal across all customer classes, with small exceptions for the establishment of low-income and senior citizen rates for eligible customers.[81] However, Act 341 also provides for the potential for the Commission to implement customer rate changes over a period of time if the Commission

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[79] *See*, Bonbright, James C. *et al.* (1988), "*Principles of Public Utility Rates*", 2nd ed., Public Utilities Reports, Inc., pp. 383-384.
[80] 2016 PA 341 § 11(1).
[81] 2016 PA 341 § 11(2).

determines that the impact of imposing cost of service rates would have a material impact on customer rates.[82] In all, the generally accepted rate-making principles are applied in Michigan the same as in other jurisdictions, though Michigan ratemaking potentially places a greater emphasis on informing rates by costs than some other jurisdictions.

B. Company's Proposed Revenue Distribution

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO DISTRIBUTE ITS CLASS REVENUE REQUIREMENTS.

A. The Company's proposed revenue allocations are based on its CCOSS results and would move each class's rates to levels that equalize its individual class ROR (or 100 percent relative rate of return ("RROR")). DTE's revenue allocations are split between those associated with the provision of power supply and distribution services. Exhibit AG-2.7 presents the Company's proposed revenue distribution under its proposed rates. The proposed revenue increase across both services and customer classes is 7.64 percent. On an individual customer class basis, the Company proposed increase ranges from a 3.66 percent increase to primary-voltage customers to an 8.86 percent increase to residential customers.

Q. WHAT DO YOU MEAN BY A RROR?

A. A RROR effectively standardizes class-specific rates of return to the overall system average. In other words, it divides the estimated class ROR by the estimated system ROR. For instance, assume that the residential class is earning a class-specific eight percent ROR and further assume that the system-wide average ROR estimated by the same CCOSS is also eight percent. The residential class, in this example, can be said

[82] 2016 PA 341 § 11(1).

to be earning a 1.0 RROR if the estimated ROR is the same as the overall system (*i.e.*, eight percent divided by eight percent equals 1.0). Put another way, any class earning a 1.0 RROR can be said to be making its full contribution to the system's overall ROR (*i.e.*, there is no cross-subsidy). A RROR that is greater than one indicates that a particular class is contributing more than the system average contribution to the Company's overall return. Likewise, a class that earns a RROR less than 1.0 can be said to be making a less-than-average contribution to the overall system and is effectively being partially subsidized by other classes.

C. Revenue Distribution Recommendations

Q. WHAT IS YOUR RECOMMENDED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a revenue distribution that reflects the alternative CCOSS recommendations discussed earlier. The ultimate revenue distribution effects of these changes will depend on the Commission's adopted revenue requirement for the Company. However, based on the Company's proposed revenue requirement, the changes discussed earlier would result in the residential customer class receiving an adjusted 6.19 percent increase in rates. Additionally, secondary customers would receive an 10.48 percent increase in rates, while primary customers would receive a 6.69 percent increase in rates.

Q. HAVE YOU PREPARED ANY EXHIBITS THAT PROVIDE EXPLANATORY RATES USING YOUR PROPOSED ALTERNATIVE CCOSS RECOMMENDATIONS AND REVENUE DISTRIBUTION?

A. Yes. Exhibit AG-2.9 presents an explanatory comparison of the resulting rates based on my proposed alternative CCOSS recommendations at the Company's proposed revenue requirement to both current and Company proposed rates.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE ALLOCATION OF COSTS ASSOCIATED WITH PRODUCTION PLANT FACILITIES?

A. I recommend that the Commission modify the weighting of the existing 4 CP 75-0-25 cost allocation method to one that equally weights demand and energy concerns, or a 4 CP 55-0-45 cost allocation methodology. My proposed 4 CP 55-0-45 cost allocation method is based on my analysis of what would constitute a fair and reasonable approximation of the relative cost of service. Specifically, my proposed 4 CP 55-0-45 would make the cost allocation of the Company's production plant consistent with recent system load factors for DTE over the last five years (2017 through 2021), which have consistently ranged between 44.4 and 48.1 percent. Furthermore, my recommendation would make the cost allocation consistent with examinations of the relative classification of individual Company generation units.

Q. WHY DO YOU FEEL THAT THE COMMISSION SHOULD REASSESS ITS POLICY WITH REGARDS TO THE APPROPRIATE ALLOCATION OF COSTS ASSOCIATED WITH PRODUCTION PLANT FACILITIES?

A. As I discussed, the current requested rate increase represents the eighth such rate increase in the past 15 years. Furthermore, these rate increases have consistently assigned a disproportionate percentage of the applicable rate increase to residential customers. These consistent, significant rate increases to residential customers have led to the Company having notably uncompetitive residential rates when compared to other regional and national electric utilities. Indeed, this is demonstrated by the Company's own benchmarking analysis, which found that both had the highest residential electric rates in the region and that these rates have been growing at a faster rate than its regional peers.[83]

Q. WHAT IS YOUR RECOMMENDATION FOR AN APPROPRIATE ALLOCATION OF SECONDARY-VOLTAGE DISTRIBUTION SYSTEMS?

A. I recommend that the Commission allocate costs associated with demand-related secondary-voltage distribution systems based on class NCP demands. The Company's proposed allocation places too much emphasis on individual customer peak loads, failing to recognize that not all customers present peak demands on the system peak at the same time. Furthermore, allocating secondary-voltage distribution costs in a manner consistent with the allocation of primary-voltage distribution costs is consistent with how these costs are typically allocated in other jurisdictions.

Q. WHAT IS YOUR RECOMMENDED REVENUE DISTRIBUTION?

A. I recommend that the Commission adopt a revenue distribution that reflects my alternative CCOSS recommendations. Ultimate revenue distribution effects of these changes will depend on the Commission's adopted revenue requirement for the Company. However, based on the Company's proposed revenue requirement, the changes discussed earlier would result in the residential customer class receiving a 6.91 percent increase in rates. Additionally, secondary customers would receive a 10.48

[83] *See*, Exhibit AG-2.3 at 4.

percent increase in rates, while primary customers would receive a 6.69 percent increase in rates.

Q. HAVE YOU PREPARED ANY EXHIBITS THAT PROVIDE EXPLANATORY RATES USING YOUR PROPOSED ALTERNATIVE CCOSS RECOMMENDATIONS AND REVENUE DISTRIBUTION?

A. Yes. Exhibit AG-2.9 presents an explanatory comparison of the resulting rates based on my proposed alternative CCOSS recommendations at the Company's proposed revenue requirement to both current and Company proposed rates.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2014-Current	Executive Director
2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-2014	Associate Executive Director
2001-2006	Associate Professor
1999-2001	Research Fellow and Adjunct Assistant Professor
1995-2000	Assistant Professor

College of the Coast and the Environment (Department of Environmental Studies)

2014-Current	Professor (Joint Appointment with CES)
2010-Current	Director, Coastal Marine Institute
2010-2014	Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)

2006-Current	Adjunct Professor

2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Michigan State University, East Lansing, Michigan

Institute of Public Utilities

2018-current	Senior Fellow

Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-1999	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

1999-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida

Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida/FlaSEIA, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2020-Current	Co-Chairperson, Energy Advisory Committee, World Trade Center New Orleans, Louisiana.
2017-Current	Member, National Petroleum Council. U.S. Department of Energy.
2007-Current	Louisiana Representative, Interstate Oil and Gas Compact

	Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Power System Operations and Planning in a Competitive Market*. (2002). With Fred I. Denny. New York: CRC Press.
2. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy.

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2. "The Potential Impact of the U.S. Carbon Capture and Storage Tax Credit Expansion on the Economic Feasibility of Industrial Carbon Capture and Storage" (2021). With Brittany Tarufelli and Brian Snyder. *Energy Policy*. Vol.149.
3. "Current Trends and Issues in Reforming State-level Solar Net Energy Metering Policies." (2020). *Journal of Energy Law and Resources*. Vol. VIII: 419-451.
4. "A cash flow model of an integrated industrial CCS-EOR project in a petrochemical corridor: a case study in Louisiana. (2019). With Brian Snyder and Michael Layne. *International Journal of Greenhouse Gas Control*. 93(08).
5. "Understanding the challenges of industrial carbon capture and storage: An example in a U.S. petrochemical corridor." (2019). With Michael Layne and Brian Snyder. *International Journal of Sustainable Energy* 38(1):13-23.

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8. “Sea level rise and coastal inundation: a case study of the Gulf Coast energy infrastructure.” (2018). With Siddhartha Narra. *Natural Resources*. 9: 150-174.

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10. “Modeling the impacts of sea-level rise, oil price, and management strategy on the costs of sustaining Mississippi delta marshes with hydraulic dredging.” (2018). with Adrian R.H. Wiegman, John W. Day, Christopher F. D’Elia, Jeffrey S. Rutherford, James T. Morris, Eric D. Roy, Robert R. Lane, and Brian F. Snyder. *Science of the Total Environment* 618 (2018): 1547-1559.

11. “Identifying Vulnerabilities of Working Coasts Supporting Critical Energy Infrastructure.” (2016). With Siddhartha Narra. *Water*. 8(1).

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13. “Economic impact of Gulf of Mexico ecosystem goods and services and integration into restoration decision-making.” (2014) With Shepard, A.N., J.F. Valentine, C.F. D’Elia, D.W. Yoskowitz. *Gulf Science*.

14. “An Empirical Analysis of Differences in Interstate Oil and Natural Gas Drilling Activity.” (2012). With Mark J. Kaiser and Christopher J. Peters. *Exploration & Production: Oil and Gas Review*. 30(1): 18-22.

15. “The Value of Lost Production from the 2004-2005 Hurricane Seasons in the Gulf of Mexico.” (2009). With Mark J. Kaiser and Yunke Yu. *Journal of Business Valuation and Economic Loss Analysis*. 4(2).

16. “Estimating the Impact of Royalty Relief on Oil and Gas Production on Marginal State Leases in the US.” (2006). With Jeffrey M. Burke and Dmitry V. Mesyanzhinov. *Energy Policy* 34(12): 1389-1398.

17. “Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds.” (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation.* 2 (November): 69-85. (*Received 2005 Best Paper Award by NRRI*).

18. “Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes.” (2004). With K.E. Hughes II. *International Energy Law and Taxation*

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21. "A Comment on the Integration of Price Cap and Yardstick Competition Schemes in Electrical Distribution Regulation." (2001). With Steven A. Ostrover. *IEEE Transactions on Power Systems.* 16 (4): 940 -942.

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3. “Competitive Bidding in the Electric Power Industry.” (2003). *Proceedings of the Association of Energy Engineers*. December 2003.

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6. “The Hydropower Industry of the United States.” (2000). With Dmitry Mesyanzhinov. In *Renewable Energy: Trends and Prospects*. Edited by E.W. Miller and A.I. Panah. Lafayette, PN: The Pennsylvania Academy of Science, 133-146.

7. “Electric Power Generation.” (2000). In the *Macmillan Encyclopedia of Energy*. Edited by John Zumerchik. New York: Macmillan Reference.

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1. Review of ***Renewable Resources for Electric Power: Prospects and Challenges***. Raphael Edinger and Sanjay Kaul. (Westport, Connecticut: Quorum Books, 2000), pp 154. ISBN 1-56720-233-0. *Natural Resources Forum*. (*2000*).

2. Review of ***Electricity Transmission Pricing and Technology***, edited by Michael Einhorn and Riaz Siddiqi. (Boston: Kluwer Academic Publishers, 1996) pp. 282. ISBN 0-7923-9643-X. *Energy Journal* 18 (1997): 146-148.

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2. “The Challenges of the Regulatory Review of Diversification Mergers.” (2016). With Michael W. Deupree. *Electricity Journal*. 29 (2016): 9-14.

3. “Unconventional Natural Gas and the U.S. Manufacturing Renaissance” (2013). *BIC Magazine*. Vol. 30: No. 2, p. 76 (March).

4. “Louisiana’s Tuscaloosa Marine Shale Development: Emerging Resource and Economic Potentials” (2012). *Spectrum*. January-April: 18-20.

5. “The Impact of Legacy Lawsuits on Louisiana’s Conventional Drilling Activity” (2012). *LOGA Industry Report*. Spring 2012: 27-34.

6. “Value of Production Losses Tallied for 2004-2005 Storms.” (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.27: 32-26 (July 21) (part 3 of 3).

7. “Model Framework Can Aid Decision on Redevelopment.” (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.26: 49-53 (July 14) (part 2 of 3).

8. “Field Redevelopment Economics and Storm Impact Assessment.” (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.25: 42-50 (July 7) (part 1 of 3).

9. “The IRS’ Latest Proposal on Tax Normalization: A Pyrrhic Victory for Ratepayers,” (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 55(1): 217-236

10. “Executive Compensation in the Electric Power Industry: Is It Excessive?” (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(4): 913-940.

11. “Renewable Portfolio Standards in the Electric Power Industry.” With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(3): 693-706.

12. “Regulating Mercury Emissions from Electric Utilities: Good Environmental Stewardship or Bad Public Policy? (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54 (2): 401-424.

13. “Using Industrial-Only Retail Choice as a Means of Moving Competition Forward in the Electric Power Industry.” (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(1): 211-223.

14. “The Nuclear Power Plant Endgame: Decommissioning and Permanent Waste Storage. (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (4): 981-997.

15. “Can LNG Preserve the Gas-Power Convergence?” (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (3):783-796.

16. “Competitive Bidding as a Means of Securing Opportunities for Efficiency.” (2004). With Elizabeth A. Downer. *Electricity and Natural Gas* 21 (4): 15-21.

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42. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

43. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

44. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

45. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information

for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

46. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

47. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

48. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

49. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

50. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

51. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "The changing nature of Gulf of Mexico energy infrastructure." (2017). Session 3B: New Directions in Social Science Research. 27th Gulf of Mexico Region Information Technology Meetings. U.S. Department of the Interior, Bureau of Ocean Energy Management, Environmental Studies Program. New Orleans, LA. August 24.

2. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). U.S. Department of Energy, 2017 Industrial Energy Technology Conference, New Orleans, LA June 21.

3. "Vulnerability assessment of the central Gulf of Mexico coast using a multi-dimensional approach." (2016). With Siddhartha Narra. Eighth International Conference on Environmental Science and Technology. June 6-10, Houston, TX.

4. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and

Leaks." (2015). With Gregory Upton. Southern Economic Association Meeting 2015. New Orleans, Louisiana. November 23.

5. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks" (2015). With Gregory Upton. 38th IAEE International Conference, Antalya, Turkey. May 26.

6. "Modifying Renewables Policies to Sustain Positive Economic and Environmental Change" (2015). IEEE Annual Green Technologies ("Greentech") Conference. April 17.

7. "The Gulf Coast Industrial Investment Renaissance and New CHP Development Opportunities." (2014). Industrial Energy and Technology Conference, New Orleans, Louisiana. May 20.

8. "Estimating Critical Energy Infrastructure Value at Risk from Coastal Erosion" (2014). With Siddhartha Narra. American's Estuaries: 7th Annual Summit on Coastal and Estuarine Habitat Restoration. Washington, D.C., November 3-6.

9. "Economies of Scale, Learning Curves, and Offshore Wind Development Costs" (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17.

10. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7.

11. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

12. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

13. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7.

14. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19.

15. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16.

16. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

17. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). U.S. Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

18. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

19. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

20. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

21. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

22. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

23. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

24. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

25. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

26. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

27. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

28. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

29. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

30. “Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach.” (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

31. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

32. “Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation.” (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

33. “Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry.” (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

34. “Modeling Regional Power Markets and Market Power.” (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

35. “Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana” (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

36. “Empirical Issues in Electric Power Transmission and Distribution Cost Modeling.” (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

37. “Modeling Electric Power Markets in a Restructured Environment.” (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

38. “Benchmarking Electric Utility Distribution Performance.” (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

39. “Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry.” (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

40. “Benchmarking Electric Utility Transmission Performance.” (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

41. “A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry.” (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

42. “New Paradigms for Power Engineering Education.” (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

43. “Cogeneration and Electric Power Industry Restructuring.” (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

44. “The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978.” (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

45. “Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS.” (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

46. “Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS.” (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

47. “Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry” (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

48. “Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries” (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

49. “Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry.” (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

50. “Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators.” (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

51. “Empirical Determinants of Nuclear Power Plant Disallowances.” (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

52. “A Cross-Sectional Model of IntraLATA MTS Demand.” (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. Panelist. “Fuel Security, Resource Adequacy & Value of Transmission.” (2019). 6th Annual Electricity Dialogue at Northwestern University: Energy and Capacity: Transitions? Northwestern University Center of Law, Regulation, and Economic Growth.

2. “Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation.” Lecture before School of the

Coast & Environment. November 5, 2011.

3. “Energy Regulation: Overview of Power and Gas Regulation.” Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

4. “Trends and Issues in Renewable Energy.” Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

5. “CES Research Projects and Status.” Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

6. “Hurricane Impacts on Energy Production and Infrastructure.” Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

7. “Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

8. “Electric Restructuring and Conservation.” (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

9. “Electric Restructuring and the Environment.” (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

10. “Electric Restructuring and Nuclear Power.” (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

11. “The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring.” (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. “Overview of Louisiana’s greenhouse gas emissions and trends.” (2021). Louisiana Energy Users Group (“LEUG”) Meeting. November 11, 2021.

2. “State of energy in Louisiana: a preview of the 2021 Gulf Coast Energy Outlook.” (2021). Financial Planning Association of Baton Rouge. November 10, 2021.

3. “Replacing natural gas and industrial decarbonization: utility and ratemaking issues.” (2021). Virtual Joint Annual Meeting: Virginia Committee for Fair Utility Rates, Old Dominion Committee for Fair Utility Rates, and Virginia Industrial Gas Users Group Workshop. September 8, 2021.

4. “Louisiana 2021 GHG Inventory: Update and summary of preliminary findings.” (2021). Presentation before the Climate Initiative Task Force. July 29, 2021.

5. “Opportunities for the development of a hydrogen economy in Louisiana.” (2021). Louisiana Energy Climate Solutions Workshop. June 15, 2021.
6. “Natural gas: Building gas system resilience. Overview of the 2021 polar vortex and its implications for gas resiliency.” (2021). National Association of State Utility Consumer Advocates (“NASUCA”). Virtual mid-year meeting. June 14, 2021.
7. “Status and briefing on the Louisiana greenhouse gas inventory and emissions analysis.” (2021). Scientific Advisory Group (“SAG”) Meeting, Governor’s Climate Initiative Task Force. March 29, 2021.
8. “Louisiana carbon capture: sinks; sources; and the role of transportation in industrial applications.” (2021). LSU Journal of Energy Law & Resources Symposium on Carbon Capture and Solutions. February 5, 2021.
9. “Natural gas outlook, 2021: production, demand, pandemic and policy.” (2021). National Association of State Utility Consumer Advocates (“NASUCA”) Monthly Natural Gas Committee Webinar. January 20, 2021.
10. “Consumer Perspectives on the Rate Design of the Future.” (2020). National Association of State Utility Consumer Advocates (“NASUCA”). Annual Conference, November 10.
11. “Evaluation of Louisiana’s Depleted Gas Reservoirs for Geological Carbon Sequestration.” (2020). Louisiana Mid-Continent Oil and Gas Association (“LMOGA”) Carbon Capture and Underground Storage (“CCUS”) Committee Meeting. August 25.
12. “The 2020 Gulf Coast Energy Outlook: COVID-19 update.” (2020). Baton Rouge Area Chamber of Commerce Business Webinar. COVID-19 and Global Supply Impacts on the Capital Region and Louisiana Economies. Baton Rouge, LA. June 3.
13. “Ratepayer benefits of reforming PURPA”. (2020). Harvard Electricity Policy Group Webinar. PURPA: A time to reform or reduce its role? March 26.
14. “Pipeline industry: economic trends and outlook”. (2020). Joint Industry Association Annual Meeting. Louisiana Mid-Continent Oil and Gas Association (“LMOGA”) and the Louisiana Oil and Gas Association (“LOGA”). Lake Charles, LA March 5.
15. “The outlook for natural gas: storm clouds ahead?” (2020). National Association of State Utility Consumer Advocates (“NASUCA”). Natural Gas Committee Webinar, February 26.
16. “The 2020 Gulf Coast Energy Outlook”. (2020). University of Louisiana Lafayette, Southern Unconventional Resources Center for Excellence. Lafayette, LA February 16.
17. “Opportunities for carbon capture, utilization, and storage in the Louisiana chemical corridor”. (2020). Air and Waste Management Association, Louisiana Section Luncheon. Gonzales, LA January 16.
18. Panelist. (2020). Baton Route Advocate, 2020 Economic Outlook Summit. Baton Rouge Advocate. January 8.

19. "2020 Louisiana business climate outlook: the view from the energy sector." (2019). American Council of Engineering Companies Fall Conference. November 21, 2019. Baton Rouge, LA

20. "The urgency of PURPA reform in protecting ratepayers." (2019). Americans for Tax Reform, Fall 2019 Coalition Leaders Summit, November 14, 2019. New Orleans, LA.

21. "Louisiana's coast and the energy industry." (2019). 2019 API Delta Chapter Joint Society Luncheon Meeting. November 12, 2019, New Orleans, LA.

22. "Reforming PURPA: implications for ratepayers." (2019). Thomas Jefferson Institute for Public Policy, Annual Energy Summit, State Policy Network Annual Meeting. Colorado Springs, CO, October 28.

23. "Natural gas outlook: supply, demand and prices." (2019). National Association of State Utility Consumer Advocates, Natural Gas Committee Monthly Meeting. July 30, 2019.

24. "The economic impacts and outlook for LNG development on the Gulf Coast." (2019). 73rd Annual Meeting of the Southern Legislative Conference of the Council of State Governments. New Orleans, LA, July 14. (prepared presentation, hurricane cancellation)

25. "Natural gas outlook: supply, demand, and prices." (2019). NASUCA Mid-Year Meeting. Portland, OR, June 20.

26. "Overview of Louisiana LNG issues and trends." (2019). Berlin: LNG, Energy Security, and Diversity Reporting Tour, LSU Center for Energy Studies. Baton Rouge, LA, May 9.

27. "Overview of Louisiana energy issues and outlook." (2019). Australian Media Visit, Greater New Orleans, Inc./Baton Rouge Area Foundation. Baton Rouge, LA, April 29.

28. "Gulf Coast Energy Outlook 2019: Regional trends and outlook." (2019). Women's Energy Network. Baton Rouge, LA, April 23.

29. "MISO Grid Vision 2033." (2019). 2019 Spring Regulator and Policymaker Forum. New Orleans, LA, April 15-16.

30. "Ratepayer benefits of reforming PURPA." (2019). LSU Center for Energy Studies Industry Advisory Council Meeting. March 27.

31. "Incentives, risk, and the changing nature of regulation." (2019). NASUCA Water Committee monthly meeting/webinar. March 13.

32. "Gulf Coast Energy Outlook 2019: Production, trade and infrastructure trends." (2019). 66th Annual Mineral Board Institute Meetings. Baton Rouge, LA, March 14.

33. "A golden age: energy outlook 2019." (2019). Engineering News Record Webinar. February 13.

34. Panelist. (2019). Baton Route Advocate, 2019 Economic Outlook Summit. Baton Rouge Advocate. January 8.

35. "MISO Grid Vision 2033." (2018). 2018 Winter Regulatory and Policymaker Forum. New Orleans, LA, December 11.

36. “Gulf Coast Energy Outlook 2019.” (2018). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2018.
37. “How LNG is transforming Louisiana’s energy economy.” (2018). Louisiana State Bar Association, Public Utility Section. Baton Rouge, LA, November 30.
38. “Overview of Louisiana LNG issues and trends.” (2018). Kean Miller Law Firm: Energy and Environmental Practice Group. Baton Rouge, LA, November 28.
39. “Infrastructure and capacity: challenges for development.” (2018). Society of Utility and Regulatory Financial Analysts (SURFA) Annual Meeting, New Orleans, LA, April 20.
40. “Louisiana industrial cogeneration trends.” (2018). Annual Louisiana Solid Waste Association Conference, Lafayette, LA, March 16.
41. “Gulf Coast industrial development: overview of trends and issues.” (2018). Gulf Coast Power Association Meetings, New Orleans, LA, February 8.
42. “Energy outlook – reflection on market trends and Louisiana implications.” (2017). IberiaBank Corporation Bank Board of Directors Meeting, New Orleans, LA. November 15.
43. “Integrated carbon capture and storage in the Louisiana chemical corridor.” (2017). Industry Associates Advisory Council Meeting, Baton Rouge, LA. November 7.
44. “The outlook for natural gas and energy development on the Gulf Coast.” (2017). Louisiana Chemical Association, Annual Meeting, New Orleans, LA. October 26.
45. “Critical energy infrastructure: the big picture on resiliency research.” (2017). National Academies of Science, Engineering, and Medicine. New Orleans, LA. September 18.
46. “The changing nature of Gulf of Mexico energy infrastructure.” (2017). 27th Gulf of Mexico Region Information Technology Meetings, New Orleans, LA, August 24.
47. “Capacity utilization, efficiency trends, and economic risks for modern CHP installations.” (2017). Industrial Energy Technology Conference, New Orleans, LA. June 21.
48. “Crude oil and natural gas outlook: Where are we and where are we going?” (2017). CCREDC Economic Trends Panel. Corpus Christi, TX, June 15.
49. “Navigating through the energy landscape.” (2017). Baton Rouge Rotary Luncheon. Baton Rouge, LA, May 24.
50. “The 2017-2018 Louisiana energy outlook.” (2017). Junior Achievement of Greater New Orleans, JA BizTown Speaker Series. New Orleans, LA, May 12.
51. “The Gulf Coast energy economy: trends and outlook.” (2017). Society for Municipal Analysts. New Orleans, LA, April 21.
52. “Gulf coast energy outlook.” (2017). E.J. Ourso College of Business, Dean’s Advisory Council, Energy Committee Meeting. Baton Rouge, LA, March 31.
53. “Recent trends in energy: overview and impact for the banking community.” (2017). Oil and Gas Industry Update, Louisiana Bankers Association. Baton Rouge, LA, March 24.

54. “How supply, demand and prices have influenced unconventional development.” (2016). Energy Annual Meeting, CLEER-University Advisory Board Lecture. New Orleans, LA, September 17.

55. “The Basics of Natural Gas Production, Transportation, and Markets.” (2016). Center for Energy Studies. Baton Rouge, LA, August 1.

56. “Gulf Coast industrial development: trends and outlook.” (2016). Investor Relations Group Meeting, Edison Electric Institute. New Orleans, LA, June 23.

57. “The future of policy and regulation: Unlocking the Treasures of Utility Regulation.” (2016). Annual Meeting, National Conference of Regulatory Attorneys. Tampa, FL, June 20.

58. “Utility mergers: where’s the beef?”. (2016). National Association of State Utility Consumer Advocates Mid-Year Meetings. New Orleans, LA, June 6.

59. “Overview of the Clean Power Plan and its application to Louisiana.” (2016). Shell Oil Company Internal Meeting. April 12.

60. “Energy and economic development on the Gulf Coast: trends and emerging challenges.” (2016). Gas Processors Association Meeting. New Orleans, LA, April 11.

61. “Unconventional Oil and Gas Drilling Trends and Issues.” (2016). French Delegation Visit, LSU Center for Energy Studies. March 16.

62. “Gulf Coast Industrial Growth: Passing clouds or storms on the horizon?” (2016). Gulf Coast Power Association Meetings. New Orleans, LA, February 18.

63. “The Transition to Crisis: What do the recent changes in energy markets mean for Louisiana?” (2016). Louisiana Independent Study Group. February 2.

64. “Regulatory and Ratepayer Issues in the Analysis of Utility Natural Gas Reserves Purchases” (2016). National Association of State Utility Consumer Advocates Gas Consumer Monthly Meeting. January 25.

65. “Emerging Issues in Fuel Procurement: Opportunities & Challenges in Natural Gas Reserves Investment.” (2015). National Association of State Utility Consumer Advocates Annual Meeting. Austin, Texas. November 9.

66. “Trends and Issues in Net Metering and Solar Generation.” (2015). Louisiana Rural Electric Cooperative Meeting. November 5.

67. “Electric Power: Industry Overview, Organization, and Federal/State Distinctions.” (2015). EUCI. October 16.

68. “Natural Gas 101: The Basics of Natural Gas Production, Transportation, and Markets.” (2015). Council of State Governments Special Meeting on Gas Markets. New Orleans, LA. October 14.

69. “Update and General Business Matters.” (2015). CES Industry Associates Meeting. Baton Rouge, Louisiana. Fall 2015.

70. “The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and

Leaks." (2015). 38th IAEE 2015 International Conference. Antalya, Turkey. May 26.

71. "Industry on the Move – What's Next?" (2015). Event Sponsored by Regional Bank and 1012 Industry Report. May 5.

72. "The State of the Energy Industry and Other Emerging Issues." (2015). Lex Mundi Energy & Natural Resources Practice Group Global Meeting. May 5.

73. "Energy, Louisiana, and LSU." (2015). LSU Science Café. Baton Rouge, Louisiana. April 28.

74. "Energy Market Changes and Impacts for Louisiana." (2015). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 22.

75. "Incentives, Risk and the Changing Nature of Utility Regulation." (2015). NARUC Staff Subcommittee on Accounting and Finance Meetings, New Orleans, Louisiana. April 22.

76. "Modifying Renewables Policies to Sustain Positive and Economic Change." (2015). IEEE Annual Green Technologies ("Greentech Conference"). April 17.

77. "Louisiana's Changing Energy Environment." (2015). John P. Laborde Energy Law Center Advisory Board Spring Meeting, Baton Rouge, Louisiana. March 27.

78. "The Latest and the Long on Energy: Outlooks and Implications for Louisiana." (2015). Iberia Bank Advisory Board Meeting, Baton Rouge, Louisiana. February 23.

79. "A Survey of Recent Energy Market Changes and their Potential Implications for Louisiana." (2015). Vistage Group, New Orleans, Louisiana. February 4.

80. "Energy Prices and the Outlook for the Tuscaloosa Marine Shale." (2015). Baton Rouge Rotary Club, Baton Rouge, Louisiana. January 28.

81. "Trends in Energy & Energy-Related Economic Development." (2014). Miller and Thompson Presentation, Baton Rouge, Louisiana. December 30.

82. "Overview EPA's Proposed Rule Under Section 111(d) of the Clean Air Act: Impacts for Louisiana." (2014). Louisiana State Bar: Utility Section CLE Annual Meeting, Baton Rouge, Louisiana. November 7.

83. "Overview EPA's Proposed Clean Power Plan and Impacts for Louisiana." (2014). Clean Cities Coalition Meeting, Baton Rouge, Louisiana. November 5.

84. "Impacts on Louisiana from EPA's Proposed Clean Power Plan." (2014). Air & Waste Management Annual Environmental Conference (Louisiana Chapter), Baton Rouge, Louisiana. October 29, 2014.

85. "A Look at America's Growing Demand for Natural Gas." (2014). Louisiana Chemical Association Annual Meeting, New Orleans, Louisiana. October 23.

86. "Trends in Energy & Energy-Related Economic Development." (2014). 2014 Government Finance Officer Association Meetings, Baton Rouge, Louisiana. October 9.

87. "The Conventional Wisdom Associated with Unconventional Resource Development." (2014). National Association for Business Economics Annual Conference, Chicago,

Illinois. September 28.

88. Unconventional Oil & Natural Gas: Overview of Resources, Economics & Policy Issues. (2014). Society of Environmental Journalists Annual Meeting. New Orleans, Louisiana. September 4.

89. "Natural Gas Leveraged Economic Development in the South." (2014). Southern Governors Association Meeting, Little Rock, Arkansas. August 16.

90. "The Past, Present and Future of CHP Development in Louisiana." (2014). Louisiana Public Service Commission CHP Workshop, Baton Rouge, Louisiana. June 25.

91. "Regional Natural Gas Demand Growth: Industrial and Power Generation Trends." (2014). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 30.

92. "The Technical and Economic Potential for CHP in Louisiana and the Impact of the Industrial Investment Renaissance on New CHP Capacity Development." (2014). Electric Power 2014, New Orleans, Louisiana. April 1.

93. "Industry Investments and the Economic Development of Unconventional Development." (2014). Tuscaloosa Marine Shale Conference & Expo, Natchez, Mississippi. March 31.

94. Discussion Panelist. Energy Outlook 2035: The Global Energy Industry and Its Impact on Louisiana, (2014). Grow Louisiana Coalition, Baton Rouge, Louisiana. March 18.

95. "Natural Gas and the Polar Vortex: Has Recent Weather Led to a Structural Change in Natural Gas Markets?" (2014). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. February 19.

96. "Some Unconventional Thoughts on Regional Unconventional Gas and Power Generation Requirements." (2014). Gulf Coast Power Association Special Briefing, New Orleans, Louisiana. February 6.

97. "Leveraging Energy for Industrial Development." (2013). 2013 Governor's Energy Summit, Jackson, Mississippi. December 5.

98. "Natural Gas Line Extension Policies: Ratepayer Issues and Considerations." (2013). National Association of State Utility Consumer Advocates Annual Meeting, Orlando, Florida. November 19.

99. "Replacement, Reliability & Resiliency: Infrastructure & Ratemaking Issues in the Power & Natural Gas Distribution Industries." (2013). Louisiana State Bar, Public Utility Section Meetings. November 15.

100. "Natural Gas Markets: Leveraging the Production Revolution into an Industrial Renaissance." (2013). International Technical Conference, Houston, TX. October 11.

101. "Natural Gas, Coal & Power Generation Issues and Trends." (2013). Southeast Labor and Management Public Affairs Committee Conference, Chattanooga, Tennessee. September 27.

102. "Recent Trends in Pipeline Replacement Trackers." (2013). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. September 19.

103. Discussion Panelist (2013). Think About Energy Summit, America's Natural Gas Alliance, Columbus Ohio. September 16-17.

104. "Future Test Years: Issues to Consider." (2013). National Regulatory Research Institute, Teleseminar on Future Test Years. August 28.

105. "Industrial Development Outlook for Louisiana." (2013). Louisiana Water Synergy Project Meetings, Jones Walker Law Firm, Baton Rouge, Louisiana. July 30.

106. "Natural Gas & Electric Power Coordination Issues and Challenges." (2013). Utilities State Government Organization Conference, Pointe Clear, Alabama. July 9.

107. "Natural Gas Market Issues & Trends." (2013). Western Conference of Public Service Commissioners, Santa Fe, New Mexico. June 3.

108. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Annual Legislative Conference, Baton Rouge, Louisiana. May 8.

109. "Infrastructure Cost Recovery Mechanism: Overview of Issues." (2013). Energy Bar Association Annual Meeting, Washington, D.C. May 1.

110. "GOM Offshore Oil and Gas." (2013). Energy Executive Roundtable, New Orleans, Louisiana. March 27.

111. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Risk Management Association Luncheon, March 21.

112. "Natural Gas Market Update and Emerging Issues." (2013). NASUCA Gas Committee Conference Call/Webinar, March 12.

113. "Unconventional Resources and Louisiana's Manufacturing Development Renaissance." (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.

114. "New Industrial Operations Leveraged by Unconventional Natural Gas." (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.

115. "What's Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff." (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.

116. "Trends, Issues, and Market Changes for Crude Oil and Natural Gas." (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.

117. "Game Changers in Crude and Natural Gas Markets." (2012). Chevron Community Advisory Panel Meeting. Belle Chase, LA, September 17.

118. "The Outlook for Renewables in a Changing Power and Natural Gas Market." (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.

119. "The Changing Dynamics of Crude and Natural Gas Markets." (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.

120. "The Really Big Game Changer: Crude Oil Production from Shale Resources and the

Tuscaloosa Marine Shale." (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.

121. "The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency." (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.

122. "Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

123. "Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

124. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.

125. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27, 2012.

126. "Louisiana's Unconventional Plays: Economic Opportunities, Policy Challenges. Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New Orleans, Louisiana. January 26, 2012.

127. "EPA's Recently Proposed Cross State Air Pollution Rule ("CSAPR") and Its Impacts on Louisiana." (2011). Bossier Chamber of Commerce. November 18, 2011.

128. "Facilitating the Growth of America's Natural Gas Advantage." (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.

129. "CSAPR and EPA Regulations Impacting Louisiana Power Generation." (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.

130. "Natural Gas Trends and Impact on Industrial Development." (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL. September 22, 2011.

131. "Energy Market Changes and Policy Challenges." (2011). Southeast Manpower Tripartite Alliance ("SEMTA") Summer Conference. Nashville, TN September 2, 2011.

132. "EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers." (2011). Workshop: "A Smarter Approach to Improving Our Environment." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.

133. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 4, 2011.

134. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council,

Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.

135. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.

136. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

137. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

138. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

139. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

140. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

141. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

142. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

143. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

144. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

145. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

146. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

147. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

148. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

149. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

150. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

151. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

152. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

153. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

154. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

155. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

156. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

157. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

158. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

159. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

160. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

161. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

162. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From

Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

163. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

164. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

165. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

166. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economics (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

167. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

168. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

169. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

170. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

171. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

172. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

173. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

174. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

175. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

176. “Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates (“NASUCA”) Gas Committee Monthly Meeting. February 13, 2006.

177. “Recent Trends in Natural Gas Markets.” (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

178. “Energy Markets: Recent Trends, Issues & Outlook.” (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

179. “Energy Outlook” (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

180. “Global and U.S. Energy Outlook.” (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

181. “Interdependence of Critical Energy Infrastructure Systems.” (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

182. “Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure.” (2006) The Economic and Market Impacts of Coastal Restoration: America’s Wetland Economic Forum II. Washington, DC September 28, 2006.

183. “Relationships between Power and Other Critical Energy Infrastructure.” (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

184. “Outlook, Issues, and Trends in Energy Supplies and Prices.” (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

185. “Energy Sector Outlook.” (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

186. “Oil and Gas Industry Post 2005 Storm Events.” (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

187. “Concentration of Energy Infrastructure in Hurricane Regions.” (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

188. “LNG—A Premier.” (2006). Presentation Given to the U.S. Department of Energy’s “LNG Forums.” Los Angeles, California. June 1, 2006.

189. “Regional Energy Infrastructure, Production and Outlook.” (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

190. “The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook.” Presentation before the Industrial Energy Technology Conference

2006. New Orleans, Louisiana, May 9, 2006.

191. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

192. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

193. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

194. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

195. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

196. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

197. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

198. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

199. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

200. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

201. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

202. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

203. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

204. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

205. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

206. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

207. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

208. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

209. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

210. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

211. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

212. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

213. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

214. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

215. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

216. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

217. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

218. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

219. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

220. “The Gulf South: Economic Opportunities Related to LNG.” Presentation before the Energy Council’s 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

221. “Natural Gas and LNG Issues for Louisiana.” Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

222. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

223. The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

224. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

225. “Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy.” Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

226. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

227. “Natural Gas Outlook: Trends and Issues for Louisiana.” Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

228. “Natural Gas Outlook” Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

229. “Competitive Bidding in the Electric Power Industry.” Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

230. “Regional Transmission Organization in the South: The Demise of SeTrans” Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

231. “Affordable Energy: The Key Component to a Strong Economy.” Presentation before the National Association of Regulatory Utility Commissioners (“NARUC”), November 18, 2003, Atlanta, Georgia.

232. “Natural Gas Outlook.” Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

233. “Issues and Opportunities with Distributed Energy Resources.” Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

234. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

235. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

236. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

237. "Merchant Power Plants and Deregulation: Issues and Impacts." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 18, 2002.

238. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

239. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

240. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

241. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

242. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

243. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

244. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

245. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

246. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

247. “Energy Conservation and Electric Restructuring.” With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

248. “Pricing and Regulatory Issues Associated with Distributed Energy.” Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: “Is the Window Closing for Distributed Energy?” Houston, Texas, October 13, 2000.

249. “Electric Reliability and Merchant Power Development Issues.” Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

250. “A Introduction to Distributed Energy Resources.” Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

251. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

252. “Electricity 101: Definitions, Precedents, and Issues.” Energy Council’s 2000 Federal Energy and Environmental Matters Conference. Loews L’Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

253. “LSU/CES Distributed Energy Resources Initiatives.” Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

254. “Distributed Energy Resources Initiatives.” Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

255. “Merchant Power Opportunities in Louisiana.” Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

256. Roundtable Discussant. “Environmental Regulation in a Restructured Market” The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

257. “The Political Economy of Electric Restructuring In the South” Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

258. “The Dynamics of Electric Restructuring in Louisiana.” Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

259. “The Implications of Electric Restructuring on Independent Oil and Gas Operations.” Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

260. “What’s Happened to Electricity Restructuring in Louisiana?” Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

261. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

262. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

263. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

264. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

265. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

266. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

267. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

268. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

269. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

270. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

271. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

272. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

273. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

274. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

275. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

276. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

277. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

278. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. D.P.U. 22-22. (2022). Before the Department of Public Utilities of the Commonwealth of Massachusetts. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval of a Performance-Based Ratemaking Plan and Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, §94 and 220 C.M.R. §5.00. On Behalf of Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate design, TFP analysis, rate increases, benchmark analysis, revenue distribution.

2. Expert Testimony. Docket No. 2021-361-G. (2022). Before the Public Service Commission of South Carolina. In the Matter of: Dominion Energy South Carolina, Inc.'s Request for Approval of New Natural Gas Energy Efficiency Programs. On Behalf of South Carolina Department of Consumer Affairs. Issues: DSM Rider, energy efficiency, shared savings. Direct and Surrebuttal.

3. Expert Report. Case No. 21-596-ST-AIR. (2022). Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc. For the Period January 1, 2021 through December 31, 2021. Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

4. Expert Report. Case No. 21-595-WW-AIR. (2022). Audit of the Application to Increase Rates of Aqua Ohio, Inc. For the Period January 1, 2021 through December 31, 2021. Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

5. Expert Testimony. Docket No. 2021.09.112. (2022). Before the Public Service Commission of the State of Montana. In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes. On Behalf of the Montana Consumer Counsel. Issues: wholesale energy hedging, market exposure, overview of PCCAM filing, demand side management costs.

6. Expert Testimony. Case No. U21090. (2021). Before the Michigan Public Service Commission. In the matter of the application of Consumers Energy Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, certain accounting approvals, and for other relief. On Behalf of the Michigan Department of the Attorney General. Issues: IRP, coal plant retirements, acquisition premiums, financial compensation mechanism.

7. Expert Testimony. Docket No 16-036-FR. (2021). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On Behalf of the Office of Arkansas Attorney

General Leslie Rutledge. Issues: netting adjustments, rate increases, projected year adjustments, reliability.

8. Expert Report. Docket JCCP No. 4861. (2021). Before the Superior Court of the State of California County of Los Angeles, Central Civil West. *Coordination Proceeding Special Title [Rule 3.550] Southern California Gas Leak Cases.* On Behalf of Toll Brothers. Issues: gas leak, public service obligation, integrity management.

9. Expert Testimony. Docket No. U-35927. (2021). Before the Louisiana Public Service Commission. *In Re: Application of 1803 Electric Cooperative, Inc. for Approval of Power Purchase Agreements and for Cost Recovery.* Direct and Cross-Answering. On Behalf of Cleco Cajun LLC. Issues: tolling agreements, generation acquisition, risk factors.

10. Expert Testimony. Docket No. 21-060-U. (2021). Before the Arkansas Public Service Commission. *In the Matter of Joint Application of Centerpoint Energy Resources Corp. and Summit Utilities Arkansas, Inc. For all Necessary Authorizations and Approvals for Summit Utilities Arkansas, Inc. To Acquire the Arkansas Assets of Centerpoint Energy Resources Corp. and for Approval of a Certificate of Public Convenience and necessity for Summit Utilities Arkansas, Inc.* Direct and Surrebuttal. On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: asset acquisition, ratepayer benefits, acquisition synergies, Rider FRP.

11. Expert Affidavit. Civil Action No. 2:21-cv-00778 (2021). Before the United States District Court for the Western District of Louisiana. *The State of Louisiana v. Joseph R. Biden, Jr.* Issues: leasing and drilling moratorium, state revenue, coastal restoration, economic activity.

12. Expert Testimony. Docket No. 21-044-U (2021). Before the Arkansas Public Service Commission. *In the Matter of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas' Request to Extend Rider FRP.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: ratepayer benefits, service quality, cost of service, FRP extension.

13. Expert Testimony. Docket No. 17-010-FR (2021). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: rate increase, investment and expense trends, revenue deficiency, leak performance.

14. Expert Testimony. Case No. U-20963 (2021). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, peak allocation, revenue distribution.

15. Expert Testimony. U-20-072, U-20-073, U-20-074. (2021). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement study and Tariff Filing designated as TA886-2 filed by Alaska Power Company, In the Matter of the Revenue Requirement study and Tariff filing designated as TA6-521 filed by Goat Lake Hydro, Inc.,*

In the Matter of the Revenue Requirement study and Tariff filing designated as TA4-573 filed by BBL Hydro, Inc. On Behalf of the Alaska Office of Attorney General. Issues: rate groups, cost of service.

16. Expert Testimony. Docket No. P20-001. (2021). Before the Louisiana Pilotage Fee Commission. *In Re: Request for Increase in Approved Pilot Complement; Increased Funding for necessary Additional Manpower; Upward Adjustment of Estimated Average Annual Pilot Compensation; and Related Relief Pursuant to LA R.S. 34:112.* On Behalf of the Louisiana Chemical Association (LCA) and Louisiana Mid-Continent Oil & Gas Association (LMOGA). Issues: unreasonable requests, fee structure, economic impact, over earnings.

17. Expert Testimony. D.P.U. 20-120. (2021). Before the Commonwealth of Massachusetts Before the Department of Public Utilities. *Petition of Boston Gas Company d/b/a National Grid Pursuant to G.L. c. 164, 94 and 220 C.M.R. 5.00 for Approval of an Increase in Base Distribution Rates and Approval of a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate increase, accelerated depreciation, benchmarking analysis, performance incentive mechanism.

18. Expert Testimony. RPU-2020-0001. (2020). Before the Iowa Utilities Board. *In Re: Iowa-American Water Company.* On Behalf of the Office of Consumer Advocate. Issues: rate increase, test trackers, RSM accounting ratemaking construct.

19. Expert Testimony. BPU Docket Nos. QO19010040 and GO20090622. (2020). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Energy Efficiency Programs and the Associated Cost Recovery Mechanisms Pursuant to the Clean Energy Act, N.J.S.A. 48:3-87.8 et seq. and 48:3-98.1 et seq.* On behalf of the Division of Rate Counsel. Issues: CBA requirements, capacity benefits, volatility benefits.

20. Expert Testimony. Docket No. 2020-125-E. (2020). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Dominion Energy South Carolina, Incorporated for Adjustments of Rates and Charges (See Commission Order No. 2020-313).* On Behalf of the South Carolina department of Consumer Affairs. Issues: cost of service, revenue allocation, rate design.

21. Answering Testimony. Before the United States of America Federal Energy Regulatory Commission. Docket No. RP20-614-000 and RP20-618-000. (2020). *Transcontinental Gas Pile Line Company, LLC.* On Behalf of the North Carolina Utilities Commission. Issues: Tariff revisions, assessment of Transco claims.

22. Expert Testimony. Docket No. 16-036-FR. (2020). *Before the Arkansas Public Service Commission. In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U. Direct and Surrebuttal*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increases, investment and expenses trends, load forecast, historic year netting adjustment, reliability issues.

23. Expert Testimony. Docket No. 2019.12.101. (2020). Before the Public Service

Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Approval of Capacity Resource Acquisition.* On the Behalf of the Montana Consumer Counsel. Issues: sale of capital asset, evaluation benefits, ratepayer cost exposure, reserve fund.

24. Expert Testimony. Formal Case No. 1162. (2020). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*. On Behalf of the Office of the People's Counsel. Issues: rate increase, revenue adjustment, weather normalization, rate design, revenue distribution.

25. Expert Testimony. Docket No. E-01345A-19-0236. (2020). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for Ratemaking Purposes to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop such Return*. Direct and Surrebuttal. On Behalf of the Utilities Division of the Arizona Corporation Commission. Issues: Cost of Service, Revenue Distribution, Rate Design.

26. Expert Testimony. Docket No. 17-010-FR. (2020). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increase, leak replacement and reduction, netting adjustment, revenue deficiency, accounting policy changes.

27. Expert Testimony. Case No. U-20697. (2020). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*. On Behalf of the Michigan Department of Attorney General. Issues: cost of service, revenue distribution, rate design.

28. Expert Testimony. Docket No. 2019.09.058. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes*. On the Behalf of the Montana Consumer Counsel. Issues: purchase power expenses, cost sharing, PCAAM power cost.

29. Expert Testimony. Formal Case No. 1156. (2020). Before the Public Service Commission of the District of Columbia. *In the matter of Potomac Electric Power Company for authority to implement a multiyear rate plan for electric distribution service in the district of Columbia.* Direct, Rebuttal, Surrebuttal, Supplemental, and Second Supplemental. On Behalf of the Office of the People's Counsel. Issues: revenue distribution, rate design, customer charge, performance metric policies, performance metric incentives.

30. Expert Testimony. Case No. U-20561. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*. On Behalf of the Michigan Department of Attorney General. Issues: Cost of service, allocation of production

plant, allocation of sub-transmission plant, revenue distribution.

31. Expert Testimony. Cause No. 45253. (2019). Before the Indiana Utility Regulatory Commission. *Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code 8-1-2-42.7 and 8-1-2-61, for (1) Authority to Modify its Rates and Charges for Electric Utility Service through a Step-In of New Rates and Charges using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customers Classes*. On Behalf of the Indiana Office of Utility Consumer Counsel. Issues: Decoupling, revenue decoupling mechanism and design, commission policy, benchmarking analysis.

32. Expert Testimony. Docket 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: Solar investment, risk assessment, proposed rider.

33. Expert Testimony. Docket No. 16-036-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

34. Expert Testimony. Docket No. 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: Solar project approval, ratepayer risk, cost allocation.

35. Expert Testimony. Docket No. 17-010-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: retail rates, leak analysis, revenue deficiency, investments.

36. Expert Testimony. Case No. U-20471. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.* On Behalf of the Michigan Department of Attorney General. Issues: load forecasting, least-cost system planning.

37. Expert Report. Docket No. 18-004422. (2019). Before the State of Florida Division of Administrative Hearings. *Peoples Gas System vs. South Sumter Gas Company, LLC and the City of Leesburg.* On Behalf of the City of Leesburg. Issues: retail rates, customer growth, sales trends and forecasts, policy, cost of service, socio-economic trends and forecasts.

38. Expert Testimony. Docket Nos. GO18101112 and EO18101113. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis.* On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, decoupling mechanisms.

39. Expert Testimony. Docket Nos. EO18060629 and GO18060630. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of the Second Energy Strong Program (Energy Strong II)*. On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, infrastructure replacement, cost recovery tracker mechanisms.

40. Expert Report. Docket No. 2011-AD-2. (2019). On Behalf of the Mississippi Public Service Commission. *Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards.* On Behalf of the Mississippi Public Utilities Staff. Issues: Net-metering, distributed generation.

41. Expert Testimony. Docket No. D2018.2.12. (2018). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.* On Behalf of the Montana Consumer Counsel. Issues: Net-metering, cost of service, revenue distribution, rate design.

42. Expert Testimony. Docket No. 19-SEPE-054-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc. for an Order Approving the Merger of Mid-Kansas Electric Company, Inc. into Sunflower Electric Power Corporation*. On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger impacts, rates, tariffs.

43. Expert Testimony. Docket No. 18-046-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Oklahoma Gas and Electric Company Pursuant to APSC Docket No. 16-052-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: formula rate plan, plant investment and expenses benchmarking analysis, reliability.

44. Expert Testimony. Docket No. 16-036-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

45. Expert Testimony. Docket No. 2017-AD-0112. (2018). Before the Mississippi Public Service Commission. *In Re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project.* On Behalf of the Mississippi Public Utilities Staff. Issues: cost of service and rate design.

46. Expert Affidavit. Docket No. 87011-E. (2018). Before the 16th Judicial District Court Parish of St. Martin State of Louisiana. *Bayou Bridge Pipeline, LLC versus 38.00 Acres, More or*

Less, Located in St. Martin Parish; Barry Scott Carline, et al. Issues: economic impacts.

47. Expert Testimony. Docket No. QO18080843. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Nautilus Offshore Wind, LLC for the Approval of the State Waters Wind Project and Authorizing Offshore Wind Renewable Energy Certificates.* On behalf of the Division of Rate Counsel. Issues: regulatory policy and cost-benefit analyses.

48. Expert Testimony. Docket No. ER18010029 and GR18010030. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief.* On behalf of the Division of Rate Counsel. Issues: rate proposal, revenue decoupling, regulatory policy, cost benchmarking.

49. Expert Testimony. Docket No. T-34695. (2018). Before the Louisiana Public Service Commission. *In re: Application for a rate increase on service originating at Grand isle and termination at St. James for Crude Petroleum as currently outlined in LPSC Tariff No. 75.2*. On Behalf of Energy XXI GOM, LLC. Issues: cost of service, rate design, and alternative regulation.

50. Expert Testimony. Docket No. 17-071-U. (2018). Before the Arkansas Public Service Commission*. In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, billing determinates.

51. Expert Testimony. Docket No. 17-010-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

52. Expert Testimony. Case No. PU-17-398. (2018). Before the North Dakota Public Service Commission. *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota*. On Behalf of the North Dakota Service Commission Advocacy Staff. Issues: cost of service, marginal cost of service, and rate design.

53. Expert Testimony. Docket No. 20170179-GU. (2018). Before the Florida Public Service Commission. *In re: Petition for rate increase and approval of depreciation study by Florida City Gas.* On Behalf of the Citizens of the State of Florida. Issues: policy issues concerning long-term gas capacity procurement.

54. Expert Testimony. Docket No. 18-KCPE-095-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar, Inc. and Great Plains Energy Incorporated.* On the Behalf of the

Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

55. Expert Testimony. Docket No. GR17070776. (2018). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"). On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

56. Expert Affidavit. Case No. 18-489. (2018). Before the Civil District Court for the Parish of Orleans, State of Louisiana. *Bayou Bridge Pipeline, LLC versus The White Castle Lumber and Shingle Company Limited and Jeanerette Lumber & Shingle CO. L.L.C.* Issues: economic impact of crude oil pipeline development.

57. Expert Testimony. Docket No. 16-036-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: cost of service, rate design, alternative regulation, formula rate plan.

58. Expert Testimony. Docket No. 2017-AD-0112. (2017). Before the Mississippi Public Service Commission. *In re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project*. On Behalf of the Mississippi Public Utilities Staff. Issues: financial analysis, rates and cost trends, economic impacts of proposal.

59. Expert Testimony. Case No. 2017-00179. (2017). Before the Public Service Commission, Commonwealth of Kentucky. *Electronic Application of Kentucky power Company For (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish a Regulatory Asset or Liability Related to the Big Sandy 1 Operation Rider; and (5) An Order Granting All Other Required Approvals and Relief.* On Behalf of the Office of the Kentucky Attorney General. Issues: rate design, revenue allocation, economic development.

60. Expert Testimony. Docket No. 17-010-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

61. Expert Testimony. Formal Case No. 1142. (2017). Before the Public Service Commission of the District of Columbia. *In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.* On Behalf of the Office of the People's Counsel. Issues: merger/acquisition policy, financial risk, ring-fencing, and reliability.

62. Expert Testimony. D.P.U. 17-05. (2017). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution*

Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00. On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: performance-based ratemaking, multi-factor productivity estimation.

63. Deposition and Testimony. (2017) Before the Nebraska Section 70, Article 13 Arbitration Panel. *Northeast Nebraska Public Power District, City of South Sioux City Nebraska; City of Wayne, Nebraska; City of Valentine, Nebraska; City of Beatrice, Nebraska; City of Scribner, Nebraska; Village of Walthill, Nebraska, vs. Nebraska Public Power District.* On the Behalf of Baird Holm LLP for the Plaintiffs. Issues: rate discounts; cost of service; utility regulation, economic harm.

64. Expert Testimony. Docket No. 16-052-U. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Application of the Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges and Tariffs.* On the Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

65. Expert Testimony. Docket No. 16-KCPE-593-ACQ. (2016). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar, Inc. by Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

66. Expert Testimony. Formal Case No. 1139. (2016). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.* On the Behalf of the Office of the People's Counsel for the District of Columbia. Issues: cost of service, rate design, alternative regulation.

67. Expert Affidavit. Docket No. CP15-558-000 (2016). Before the United States of America Federal Energy Regulatory Commission. *PennEast Pipeline Company, LLC*. Affidavit and Reply Affidavit. On the Behalf of the New Jersey Division of Rate Counsel. Issues: pipeline capacity, peak day requirements.

68. Expert Testimony. Docket No. RPU-2016-0002. (2016). Before the Iowa Utilities Board. *In re: Iowa American Water Company application for revision of rates.* On behalf of the Citizens of the State of Florida. Issue: revenue stabilization mechanism, revenue decoupling.

69. Expert Testimony. Docket No. 15-015-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: formula rate plan evaluation.

70. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: load forecasting.

71. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: off-system sales incentives.

72. Expert Testimony. Project No. 5-103. (2016). United States of America Federal Energy Regulatory Commission. *Confederated Salish and Kootenai Tribes Energy Keepers, Incorporated*. On behalf of the Flathead, Mission, and Jocko Valley Irrigation Districts and the Flathead Joint Board of Control of the Flathead, Mission, and Jocko Valley Irrigation Districts.

73. Expert Testimony. Docket No. 15-098-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas for a General Change or Modification in its Rates, Charges and Tariffs.* On behalf of the Office of the Arkansas Attorney General. Issues: formula rate plan, cost of service and rate design.

74. Expert Testimony. BPU Docket No. GM15101196. (2016). *In the Matter of the Merger of Southern Company and AGL Resources, Inc*. On behalf of the New Jersey Division of Rate Counsel. Issues: merger standards of review, customer dividend contributions, synergy savings and costs to achieve, ratemaking treatment of merger-related costs.

75. Expert Testimony. Docket No. 15-078-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Joint Application of SourceGas Inc., SourceGas LLC, SourceGas Holdings LLC and Black Hills Utility Holdings, Inc. for all Necessary Authorizations and Approvals for Black Hills Utility Holdings, Inc. to Acquire SourceGas Holdings LLC.* On behalf of the Office of the Arkansas Attorney General. Issues: public policy and regulatory policy associated with the acquisition.

76. Expert Testimony. Docket No. 15-031-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of SourceGas Arkansas Inc. for an Order Approving the Acquisition of Certain Storage Facilities and the Recovery of Investments and Expenses Associated Therewith.* On behalf of the Office of the Arkansas Attorney General. Issues: cost-benefit analysis, transmission cost analysis, and a due diligence analysis.

77. Expert Testimony. Docket No. 15-015-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.* On behalf of the Office of the Arkansas Attorney General. Issues: economic development riders and production plant cost allocation.

78. Expert Testimony. Docket No. 7970. (2015). Before the Vermont Public Service Board. *Petition of Vermont Gas Systems, Inc., for a certificate of public good pursuant to 30 V.S.A.§ 248, authorizing the construction of the "Addison Natural Gas Project" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 miles of new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont*.

On behalf of AARP-Vermont. Issues: net economic benefits of proposed natural gas transmission project.

79. Expert Testimony. File No. ER-2014-0370 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of Kansas City Power & Light Company for Authority Implement A General Rate Increase for Electric Service*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, class cost of service, and policy and ratemaking considerations in connection with electric vehicle charging stations.

80. Expert Testimony. File No. ER-2014-0351 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of The Empire District Electric Company for Authority To File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, and class cost of service.

81. Expert Testimony. D.P.U. 14-130 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of the Company's 2015 Gas System Enhancement Program Plan, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015.* On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

82. Expert Testimony. D.P.U. 14-131 (2015). Before the Massachusetts Department of Public Utilities. *Petition of The Berkshire Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

83. Expert Testimony. D.P.U. 14-132 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for approval by the Department of Public Utilities of the Companies' Gas System Enhancement Program for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

84. Expert Testimony. D.P.U. 14-133 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Liberty Utilities for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

85. Expert Testimony. D.P.U. 14-134 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

86. Expert Testimony. D.P.U. 14-135 (2015). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

87. Expert Report. Docket No. X-33192 (2015). Before the Louisiana Public Service Commission. *Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana.* On behalf of the Louisiana Public Service Commission. Issues: cost-benefit, cost of service, rate impact.

88. Expert Testimony. F.C. 1119 (2014). Before the District of Columbia Public Service Commission. *In the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and new Special Purpose Entity, LLC*. On behalf of the Office of the People's Counsel. Issues: economic impact analysis, reliability, consumer investment fund, regulatory oversight, impacts to competitive electricity markets.

89. Expert Report. Civil Action 1:08-cv-0046 (2014). Before the U.S. District Court for the Southern District of Ohio. *Anthony Williams, et al., v. Duke Energy International, Inc., et al.* On behalf of Markovits, Stock & DeMarco, Attorneys & Counselors at Law. Issues: public utility regulation, electric power markets, economic harm.

90. Expert Testimony. D.P.U. 14-64 (2014). Before the Massachusetts Department of Public Utilities. *NSTAR Gas Company/HOPCO Gas Services Agreement. On behalf of the Office of the Public Advocate*. Issues: certain ratemaking features associated with the proposed Gas Service Agreement.

91. Expert Testimony. Docket Nos. 14-0224 and 14-0225 (2014). Before the Illinois Commerce Commission. *In the Matter of the Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service (consolidated)*. On behalf of the People of the State of Illinois. Issues: test year expenses, cost benchmarking analysis, pipeline replacement, and leak rate comparisons.

92. Expert Testimony. Docket 8191 (2014). Before the Vermont Public Service Board. *In Re: Petition of Green Mountain Power Corporation for Approval of a Successor Alternative Regulation Plan.* On the behalf of AARP-Vermont. Issues: Alternative Regulation.

93. Expert Testimony. Docket No. 2013-00168 (2014). Before the Maine Public Utilities Commission. *In the Matter of the Request for Approval of an Alternative Rate Plan (ARP 2014) Pertaining to Central Maine Power Company*. On behalf of the Office of the Public Advocate. Issues: class cost of service study, marginal cost of service study, revenue distribution and rate design.

94. Expert Testimony. D.P.U. 13-90 (2013). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges and increase in base distribution rates for electric service.* On behalf of the Office of the

Ratepayer Advocate. Issues: capital cost adjustment mechanism and performance-based regulation.

95. Expert Testimony. BPU Docket Nos. EO13020155 and GO13020156. (2013). Before the State of New Jersey Board of Public Utilities. *I/M/O The Petition of Public Service Electric & Gas Company for the Approval of the Energy Strong Program.* On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

96. Expert Testimony. D.P.U. 13-75 (2013). Before the Massachusetts Department of Public Utilities. *Investigation by the Department of Public Utilities on its Own Motion as to the Propriety of the Rates and Charges by Bay State Gas Company d/b/a Columbia Gas of Massachusetts set forth in Tariffs M.D.P.U. Nos. 140 through 173, and Approval of an Increase in Base Distribution Rates for Gas Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on April 16, 2013, to be effective May 1, 2013*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement, and leak rate comparisons; environmental benefits analysis; O&M offset; and cost benchmarking analysis.

97. Expert Testimony. Docket No. 13-115 (2013). Before the Delaware Public Service Commission. *In the Matter of the Application of Delmarva Power & Light Company FOR an Increase in Electric Base Rates and Miscellaneous Tariff Changes* (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.

98. Expert Testimony. Formal Case No. 1103 (2013). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. On the Behalf of the Office of the People's Counsel of the District of Columbia. Issues: Pro forma adjustment for reliability investments.

99. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue distribution, and rate design

100. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.

101. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

102. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

103. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. *In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer*. On the Behalf of the Colorado Office of Consumer Counsel. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.

104. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program*. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.

105. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program.* On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.

106. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

107. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public Utilities. *In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.

108. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.

109. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. *In Re: Potomac Electric Power Company ("Pepco") General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

110. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. *In Re: the Delmarva Power and Light Company General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

111. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms.

112. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

113. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. *In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase*. On the Behalf of the Public Advocate. January 31, 2012. Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization Adjustments, Class Cost of Service Study, Rate Design.

114. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

115. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's Counsel of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. Issues: Regulatory lag, ratemaking principles, reliability-related capital expenditure tracker proposals.

116. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson.* Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

117. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S.

Environmental Protection Agency. *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

118. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. *On the Behalf of the Maryland Office of People's Counsel. In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and Revise its Terms and Conditions for Gas Service*. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

119. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

120. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. *In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company*. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)

121. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Capital Cost Rider, Revenue Decoupling.

122. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Pipeline Replacement Rider, Revenue Decoupling.

123. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

124. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

125. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

126. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

127. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

128. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

129. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

130. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

131. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

132. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

133. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

134. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

135. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

136. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

137. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

138. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

139. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

140. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

141. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

142. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

143. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

144. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

145. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

146. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

147. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

148. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

149. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

150. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

151. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

152. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

153. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

154. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

155. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

156. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

157. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

158. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their

customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

159. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

160. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

161. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

162. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

163. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

164. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

165. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

166. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed

Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

167. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

168. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

169. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

170. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

171. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

172. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

173. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

174. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al*. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

175. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

176. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

177. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

178. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

179. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

180. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

181. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

182. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

183. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

184. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

185. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

186. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central

Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

187. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

188. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

189. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

190. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

191. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

192. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

193. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

194. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

195. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

196. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation.

Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

197. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

198. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Contributor, 2014-2018, *Wall Street Journal*, *Journal Reports*, Energy

Editorial Board Member, 2015-2017, *Utilities Policy*

Referee, 2014-Current, *Utilities Policy*

Referee, 2010-Current, *Economics of Energy & Environmental Policy*

Referee, 1995-Current*, Energy Journal*

Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*

Referee, 2005, *Energy Policy*

Referee, 2004, *Southern Economic Journal*

Referee, 2002, *Resource & Energy Economics*

Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists ("IAEE"), United States Association of Energy Economics ("USAEE"), the National Association for Business Economics ("NABE"), and the Energy Bar Association (National and Louisiana Chapter; current Board member of LA chapter).

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as “Top 40 Under 40” (2003).

Omicron Delta Epsilon (1992-Current).

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Energy and the Environment (Survey Course)

Principles of Microeconomic Theory

Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept. of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on “Society and the Coast.”

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

“The Gulf Coast Energy Situation: Outlook for Production and Consumption.” Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

“The Impact of Hurricane Katrina on Louisiana’s Energy Infrastructure and National Energy Markets.” Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

“Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation.” Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

“Regulatory and Ratemaking Issues with Cost and Revenue Trackers.” Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

"Natural Gas Issues and Recent Market Trends." Michigan State University Institute of Public Utilities, GridSchool Regulatory Studies Program, East Lansing, Mich., March 29, 2017.

"Gas Supply Planning and Procurement: Regulatory Overview and issues." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Natural Gas Supply Issues and Challenges." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Incentives, Risk and Changes in the Nature of Regulation." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 18, 2017.

"Traditional and Alternative Forms of Regulation: Background and Overview." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Utility and policy motivations for risk and change." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Incentives and Formula Based Methods." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

THESIS/DISSERTATIONS COMMITTEES

Active:
1 Thesis Committee Memberships (Environmental Studies)
2 Ph.D. Dissertation Committee (Economics)
Completed:
8 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Committee Member, Energy Education Curriculum Committee. E.J. Ourso College of Business. LSU (2016-Current).

Chairman, LSU Energy Initiative/LSU Energy Council (2014-Current).

Co-Director & Steering Committee Member, LSU Coastal Marine Institute (2009-2014).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-2014); Full Member (2014-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority

Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Board Member (2018). Energy Bar Association, Louisiana Chapter.

Program Committee Member (2017). Gulf Coast Power Association Conference. New Orleans.

Program Committee Member (2016). Gulf Coast Power Association Conference. New Orleans.

Program Committee Member (2015). Gulf Coast Power Association Workshop/Special Briefing. "Gulf Coast Disaster Readiness: A Past, Present and Future Look at Power and Industry Readiness in MISO South."

Advisor (2008). National Association of Regulatory Utility Commissioners. Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Table of Schedules

Analysis of Historic Company Rates

Witness Dismukes
Case No. 20836
Exhibit AG-2.1

		Residential			Secondary			Primary			Lighting and Unmetered			Total Electricity		
Case Number	Year	Total Present Revenues ($000)	Total Proposed Revenues ($000)	Change (%)	Total Present Revenues ($000)	Total Proposed Revenues ($000)	Change (%)	Total Present Revenues ($000)	Total Proposed Revenues ($000)	Change (%)	Total Present Revenues ($000)	Total Proposed Revenues ($000)	Change (%)	Total Present Revenues ($000)	Total Proposed Revenues ($000)	Change (%)
U-15244	2008	1,812,756	1,895,013	4.5%	1,177,469	1,158,817	-1.6%	1,610,042	1,628,382	1.1%	54,909	54,510	-0.7%	4,655,176	4,736,722	1.8%
U-15768	2010	1,851,835	1,985,097	7.2%	1,007,777	1,046,024	3.8%	1,463,024	1,501,049	2.6%	55,025	62,300	13.2%	4,377,661	4,594,470	5.0%
U-16472	2011	1,998,116	2,113,118	5.8%	1,083,860	1,108,984	2.3%	1,508,078	1,552,464	2.9%	62,607	65,621	4.8%	4,652,661	4,840,187	4.0%
U-17767	2015	2,065,624	2,296,138	11.2%	1,098,165	1,135,525	3.4%	1,278,126	1,248,109	-2.3%	59,327	59,644	0.5%	4,501,242	4,739,416	5.3%
U-18014	2017	2,247,830	2,298,349	2.2%	1,117,206	1,190,086	6.5%	1,192,584	1,249,769	4.8%	60,147	63,899	6.2%	4,617,767	4,802,103	4.0%
U-18255	2018	2,339,795	2,368,765	1.2%	1,202,992	1,230,759	2.3%	1,226,505	1,233,998	0.6%	62,463	63,471	1.6%	4,831,755	4,896,993	1.4%
U-20162	2019	2,356,276	2,469,642	4.8%	1,234,113	1,238,042	0.3%	1,217,783	1,221,232	0.3%	59,688	64,106	7.4%	4,867,860	4,993,022	2.6%
U-20561	2020	$ 2,452,638	$ 2,584,574	5.4%	$ 1,227,353	$ 1,279,787	4.3%	$ 1,215,847	$ 1,217,838	0.2%	$ 64,201	$ 66,133	3.0%	$ 4,960,039	$ 5,148,332	3.8%
U-20836	**2022**	**$ 2,659,651**	**$ 2,892,516**	**8.8%**	**$ 1,267,121**	**$ 1,364,702**	**7.7%**	**$ 1,183,965**	**$ 1,232,681**	**4.1%**	**$ 68,659**	**$ 77,720**	**13.2%**	**$ 5,179,396**	**$ 5,567,619**	**7.5%**
Change U-15244 to U-20836		**$ 1,812,756**	**$ 2,892,516**	**59.6%**	**$ 1,177,469**	**$ 1,364,702**	**15.9%**	**$ 1,610,042**	**$ 1,232,681**	**-23.4%**	**$ 54,909**	**$ 77,720**	**41.5%**	**$ 4,655,176**	**$ 5,567,619**	**19.6%**
			Avg. Annual	**4.3%**		**Avg. Annual**	**1.1%**		**Avg. Annual**	**-1.7%**		**Avg. Annual**	**3.0%**		**Avg. Annual**	**1.4%**

Source: Company Compliance Filings; Company Petition, Attachment A.

Spring 2019 Electric Rate and Bill Benchmarking – GRC Committee

May 21, 2019

Today we are sharing preliminary 2018 benchmarking results for electric rates and bills

DTE Energy

	Fall 2018 (Distributed 12/21/18)	Spring 2019 (Today's update)
Rates	• 2018 through August (preliminary) • 2017 full year (final)	• 2018 full year (preliminary)
Residential Bills	• 2017 full year (final)	• 2018 full year (preliminary)

Note: Preliminary benchmarking refers to results based on the sum of monthly data (from EIA form 861M). Final data refers to results from reconciled full-year data (from EIA form 861 for electric and EIA Form 176 for gas)

Executive Summary

Rates

- From 2017 to 2018, DTE Electric residential and business rates increased while regional and national averages decreased or remained flat; Michigan performed worse and appears to be losing ground against regional and national averages
- In 2018, Michigan and DTE average total retail rates were 8% above the US average and 14% above the regional average
  - Michigan and DTE average residential rates were both 21% above the US average and continue to compare unfavorably to regional peers
  - Michigan average business rates were 4% above the US average while DTE's rates were at the average, though challenged compared to regional peers
  - Michigan average industrial rates were 6% above the US average while DTE industrial rates were 3% below the US average; outside of IL we are a regional leader
- DTE Electric's 2018 residential, business and industrial rates were at or below the Michigan average
- The changes in DTE Electric retail rates compare favorably to our regional average over the 5 year period but less so in the 1 and 3 year time period
  - DTE residential rate changes compare favorably to the regional average for the 5 year period but were higher over the 1 and 3 year periods
  - DTE total business rate changes compare favorably to the regional average over 5 years but were higher over the 1 and 3 year periods
  - DTE industrial rates changes remain favorable compared to the regional average over the 1, 3 and 5 year periods

Executive Summary (cont.)

Residential Bills

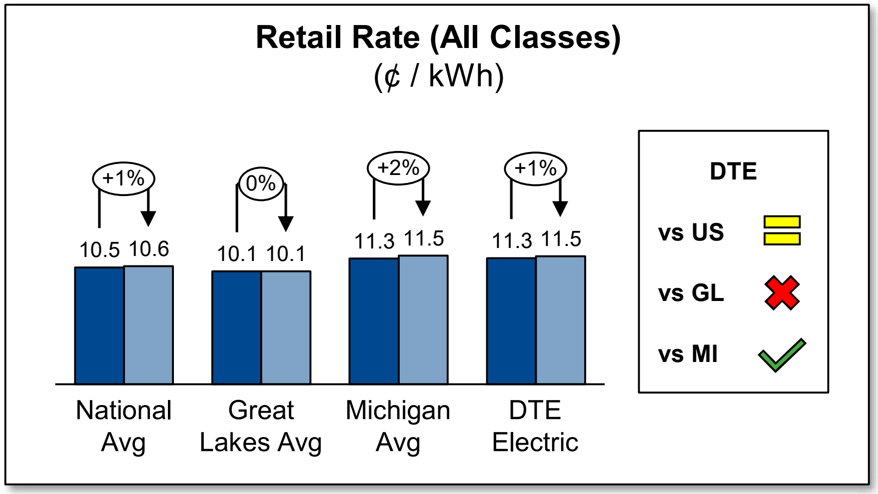
- In 2018, DTE residential electric usage was 27% below the US average but increased by 7% year over year
- In 2018, DTE saw a similar increase in average residential usage per customer compared to other Great Lakes states
- A non-uniform 2018 increase in cooling degree days explains a majority of the state usage increases and effective residential rate behavior
- DTE average electric bills increased 7% from 2017 but remain 11% below the national average
- However, Michigan residential electric and gas utility expenditures are low relative to both the recent past and the national average
- Within Michigan, residential electric and gas utility expenditures remain small relative to other typical categories of household spend

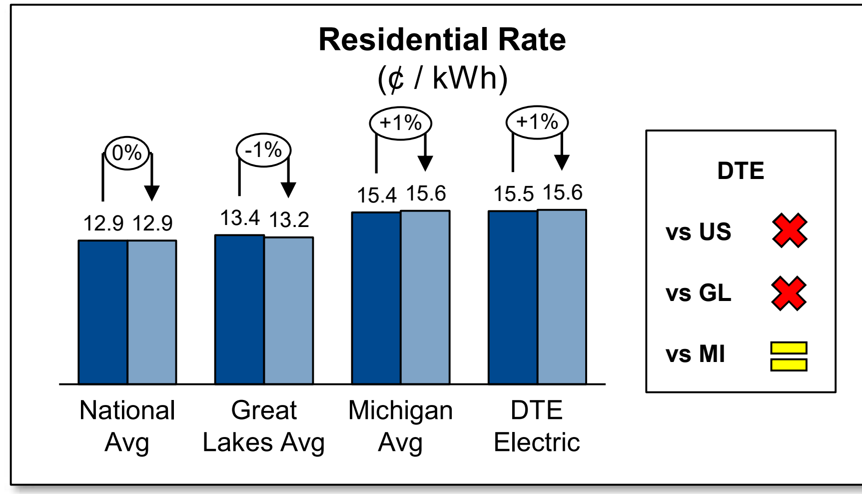
DTE Spring 2019 Rate Benchmarking Study

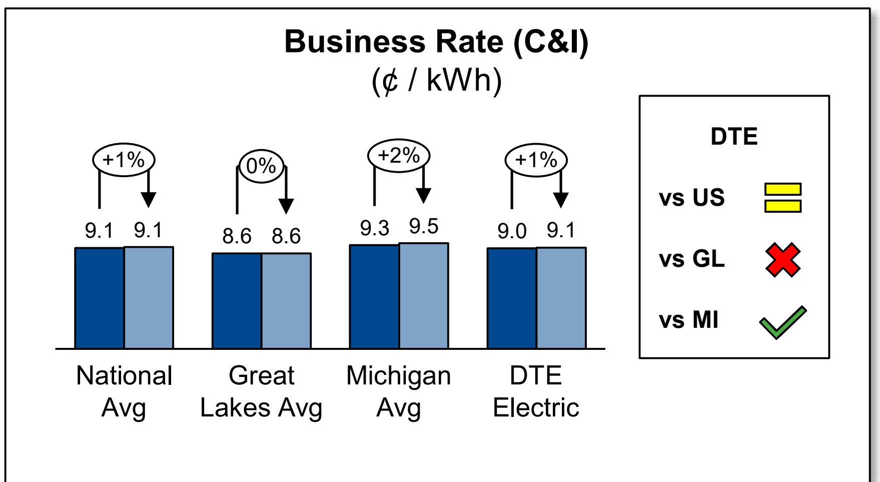
From 2017 to 2018, DTE Electric residential and business rates increased while regional and national averages decreased or remained flat

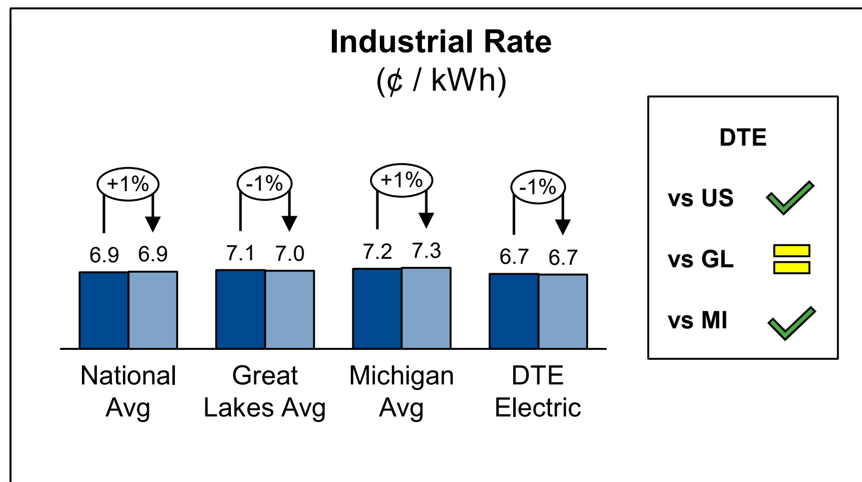
DTE Energy

2017 2018



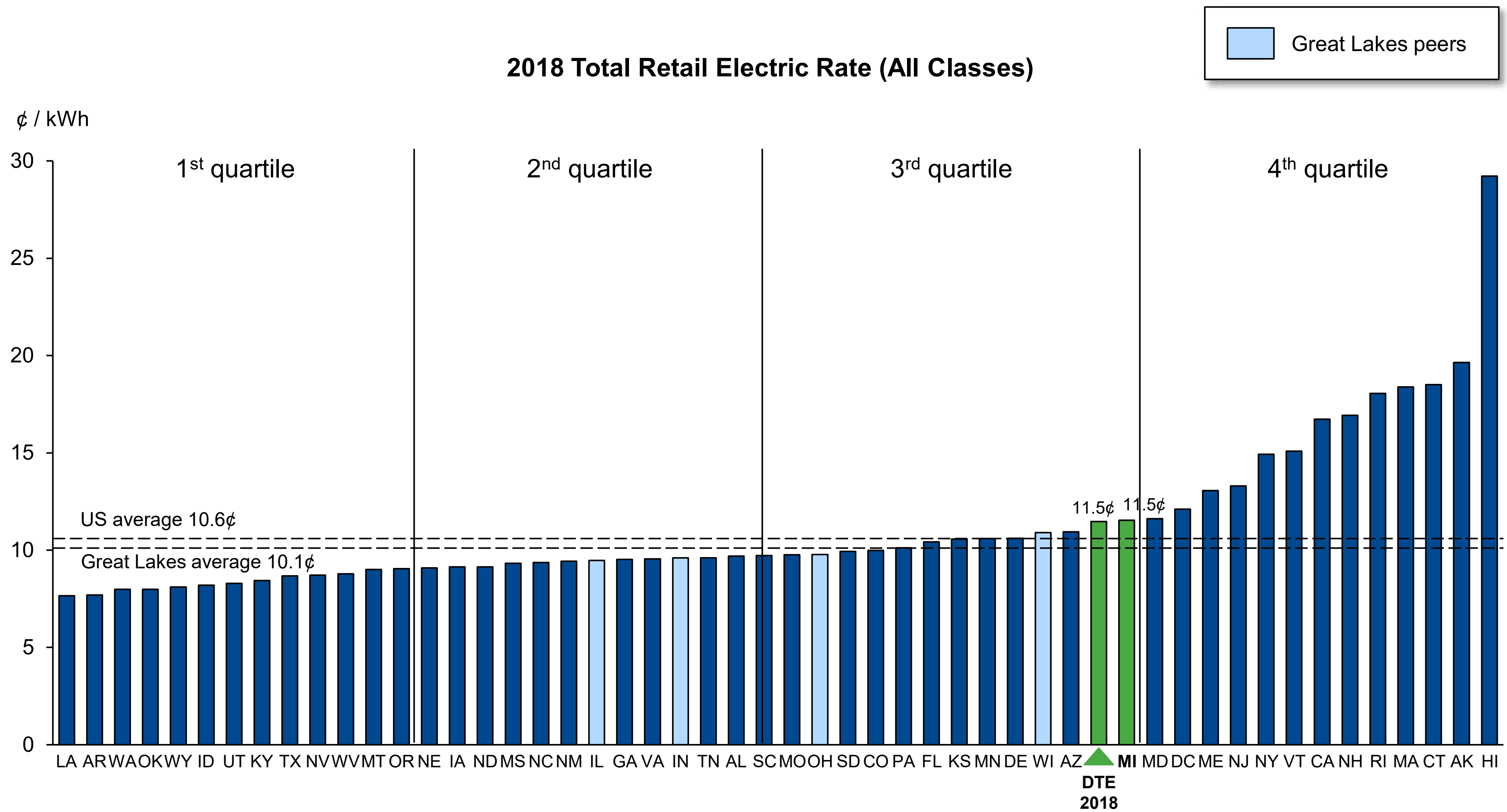






Source: EIA form 861 and 861M

In 2018, Michigan and DTE average total retail rates were 8% above the US average and 14% above the regional average

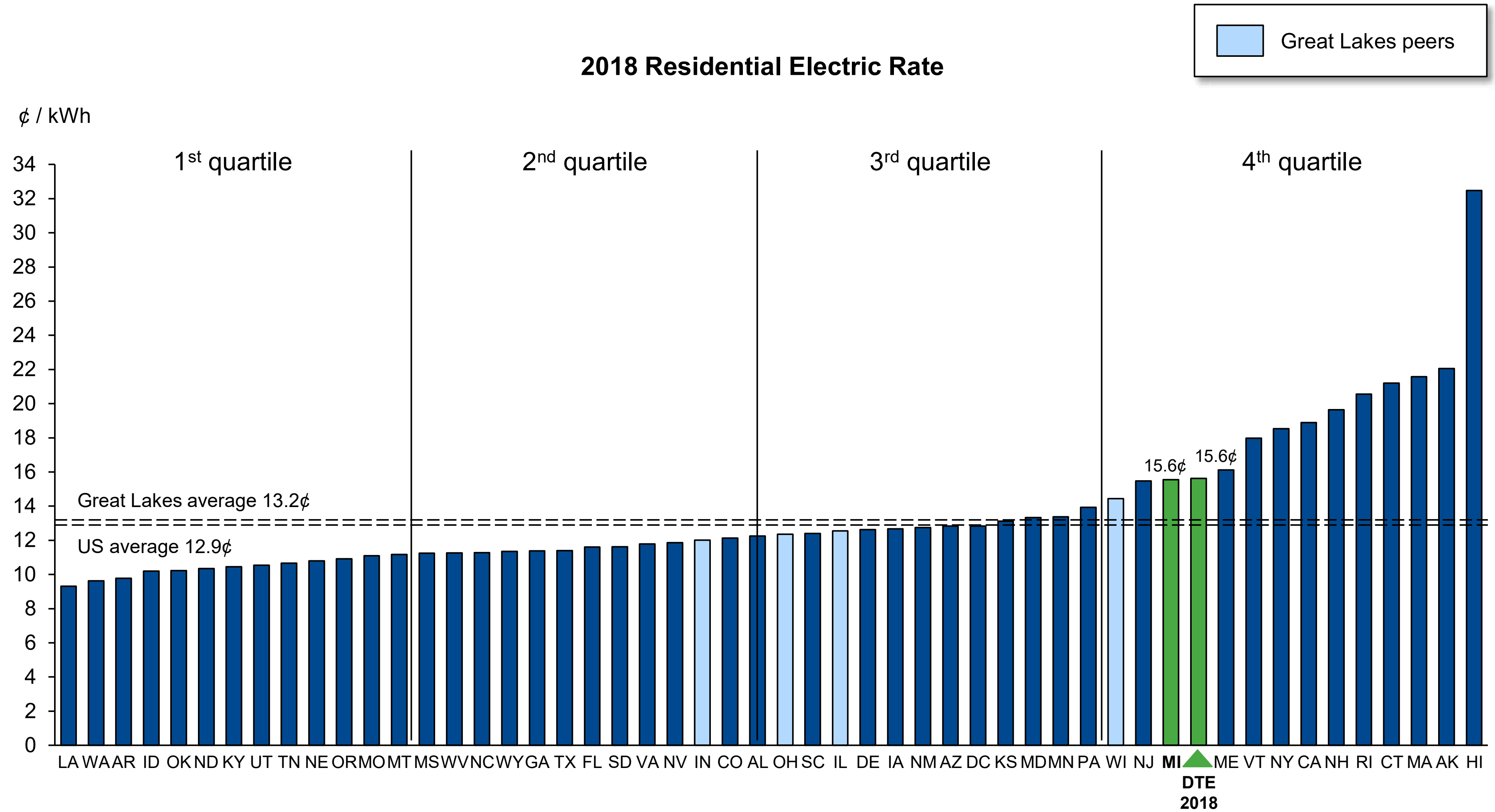


Source: EIA form 861M

DTE Spring 2019 Rate Benchmarking Study

Michigan and DTE average residential rates were both 21% above the US average and continue to compare unfavorably to regional peers

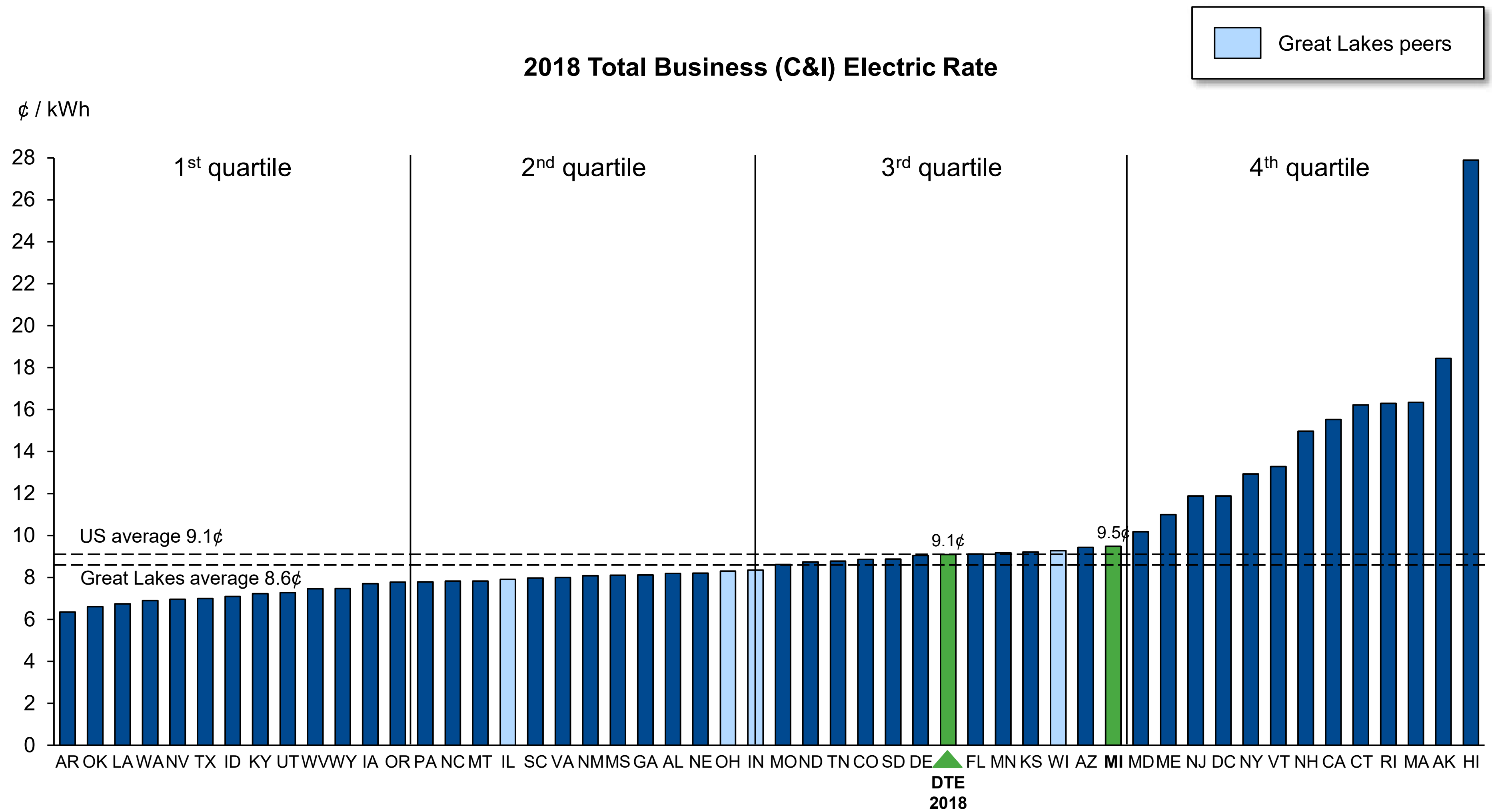
DTE Energy



Source: EIA form 861M

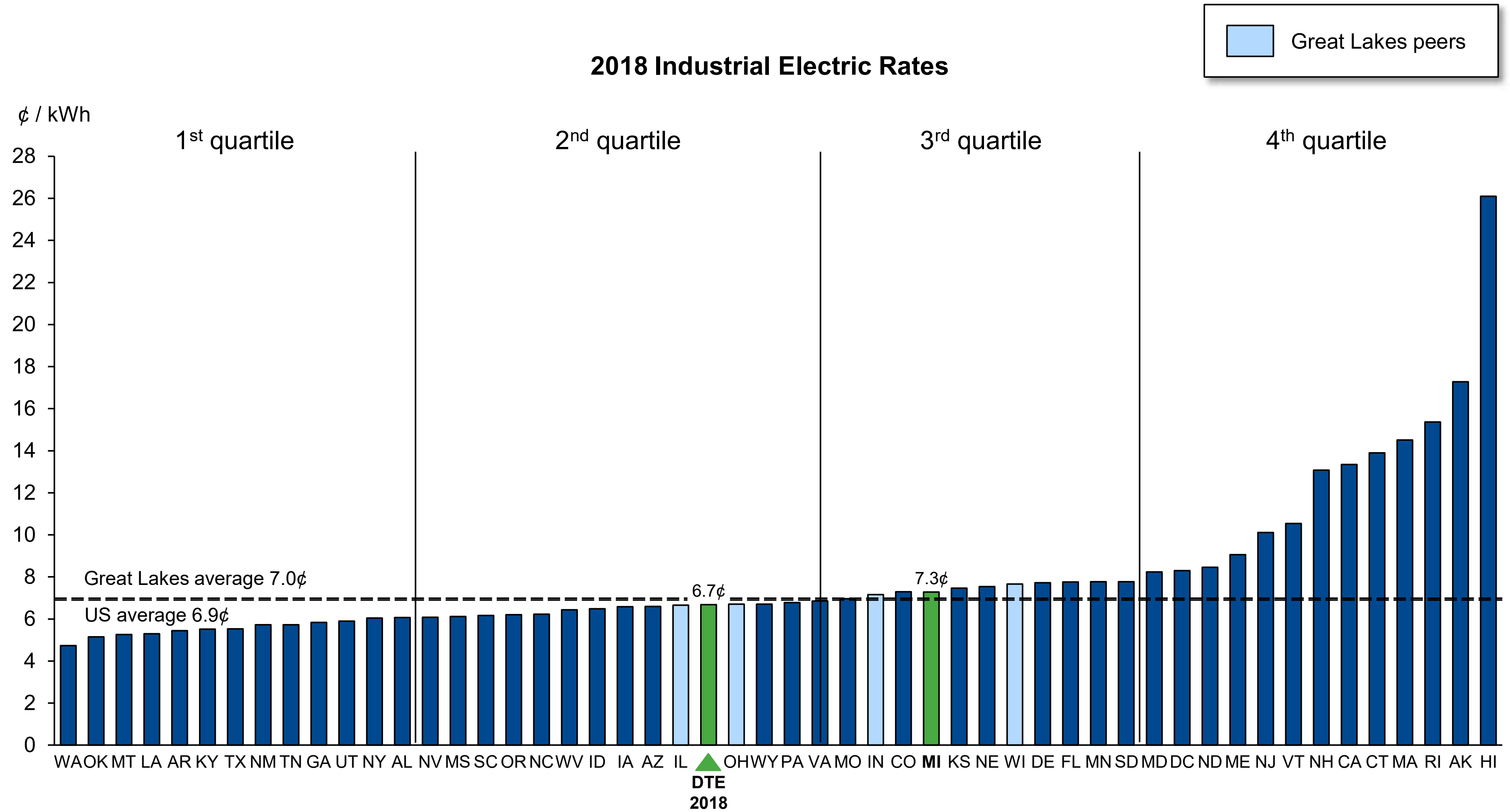
DTE Spring 2019 Rate Benchmarking Study

Michigan average business rates were 4% above the US average while DTE's rates were at the average, though challenged compared to regional peers



Source: EIA form 861M

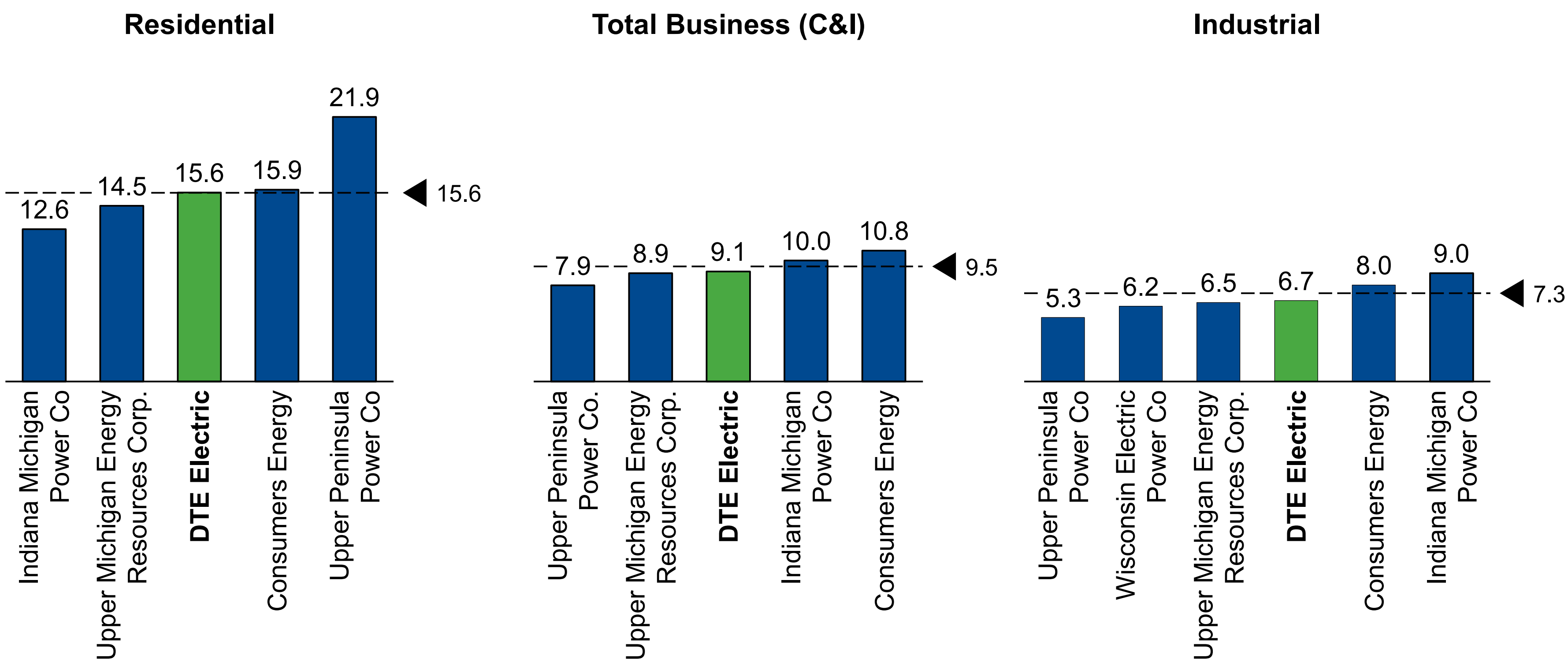
Michigan average industrial rates were 6% above the US average while DTE industrial rates were 3% below the US average; outside of IL we are a regional leader



Source: EIA form 861M

DTE Electric's 2018 residential, business and industrial rates were at or below the Michigan average

2018 Rates across Michigan
(¢ / kWh)

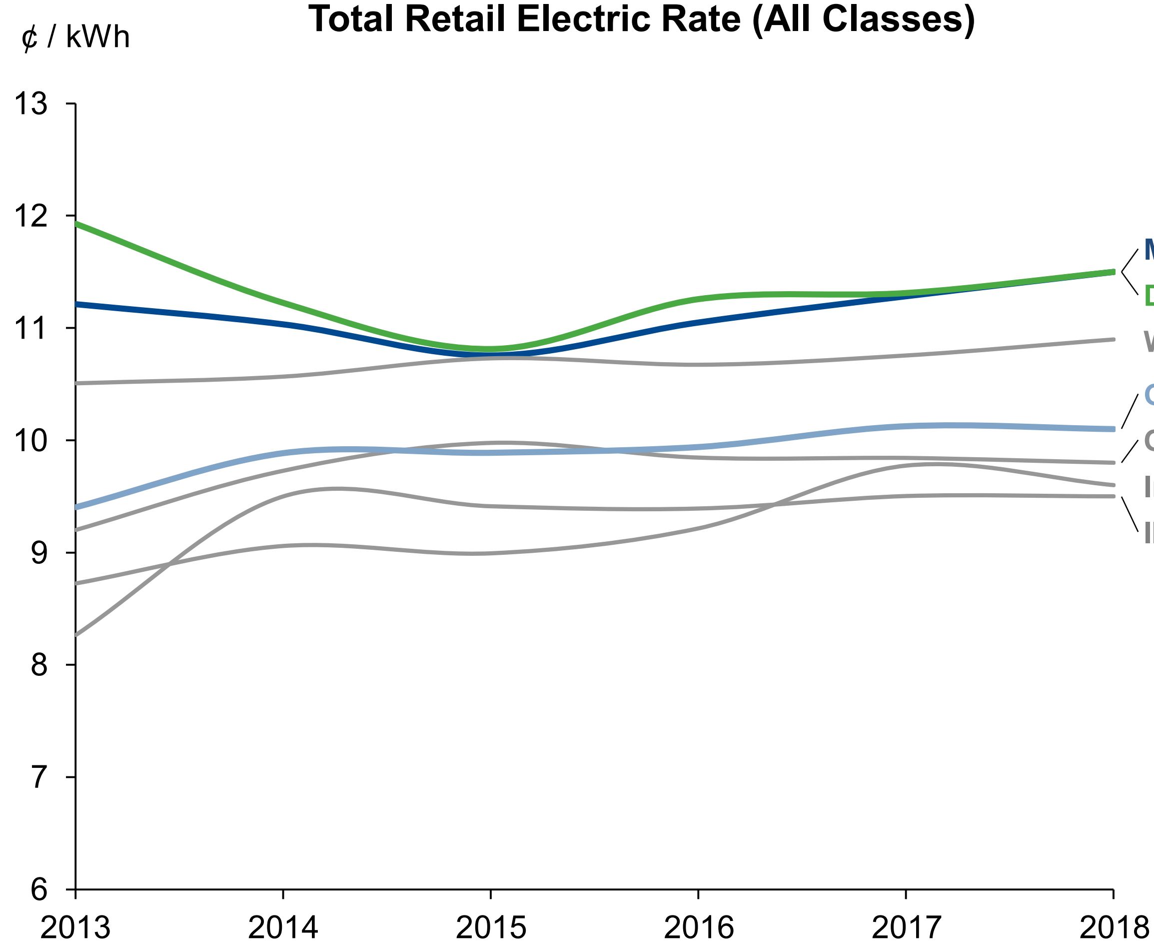


DTE defines the median in Michigan and is below average

Source: EIA form 861M

The changes in DTE Electric retail rates compare favorably to our regional average over the 5 year period but less so in the 1 and 3 year time period

Total Retail Electric Rate (All Classes)



Average annual growth

	1-year	3-year	5-year
Michigan	**1.9%**	**2.3%**	**0.5%**
DTE	**1.7%**	**2.1%**	**-0.7%**
Wisconsin	1.3%	0.5%	0.7%
Great Lakes avg.	**-0.3%**	**0.7%**	**1.4%**
Ohio	-0.4%	-0.6%	1.3%
Indiana	-1.8%	2.2%	1.9%
Illinois	0%	0.3%	2.8%

The primary driver for this was significant above average residential usage due to higher cooling degree days compared to historical averages[1]

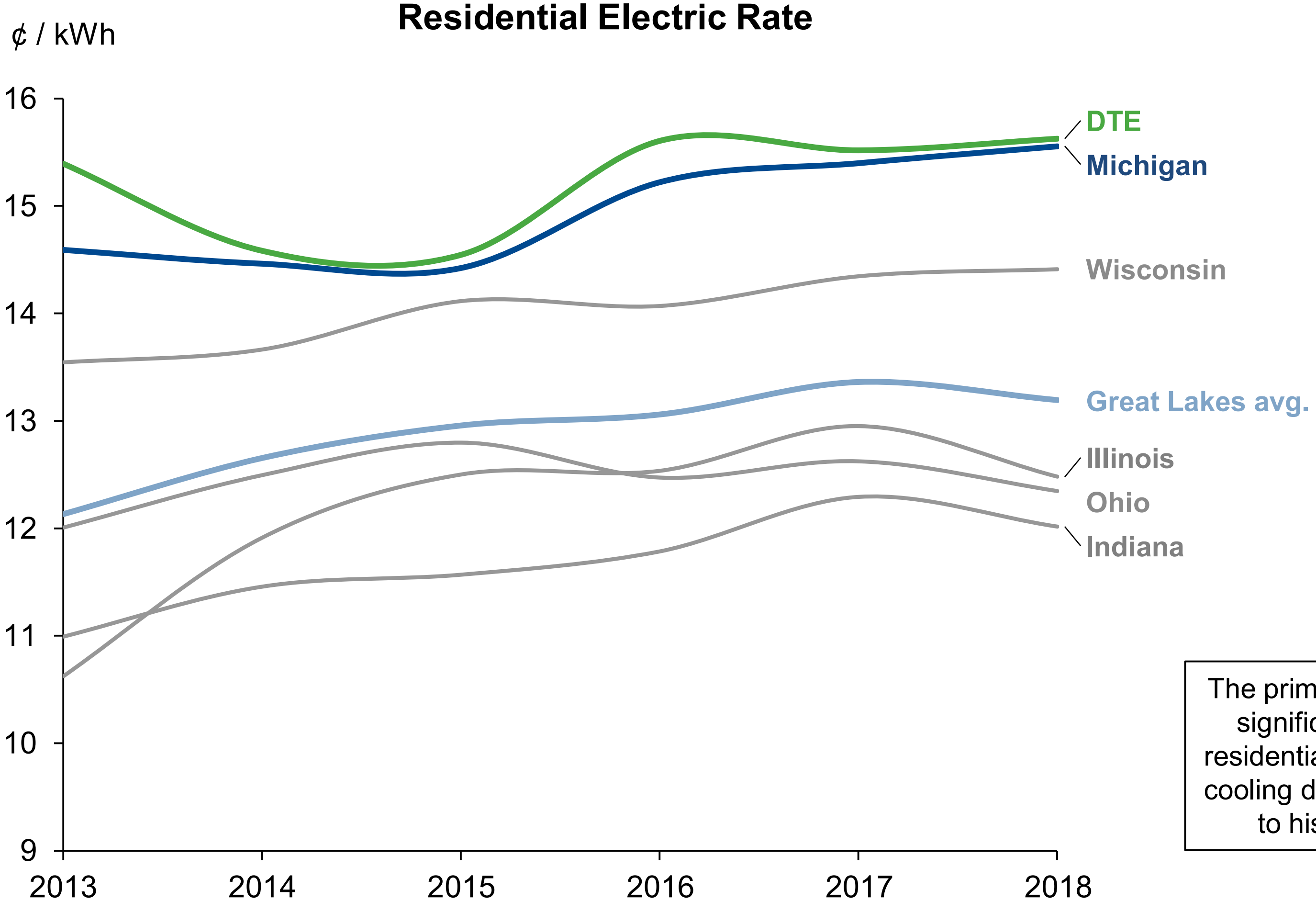
Source: EIA form 861M and 861

1. See page 16 for further details

DTE residential rate changes compare favorably to the regional average for the 5 year period but were higher over the 1 and 3 year periods

DTE Energy

Residential Electric Rate



Average annual growth

	1-year	3-year	5-year
DTE	0.7%	2.4%	0.3%
Michigan	1.0%	2.6%	1.3%
Wisconsin	0.7%	0.7%	1.2%
Great Lakes avg.	-1.3%	0.6%	1.7%
Illinois	-3.6%	-0.1%	3.3%
Ohio	-2.2%	-1.2%	0.6%
Indiana	-2.2%	1.3%	1.8%

The primary driver for this was significant above average residential usage due to higher cooling degree days compared to historical averages[1]

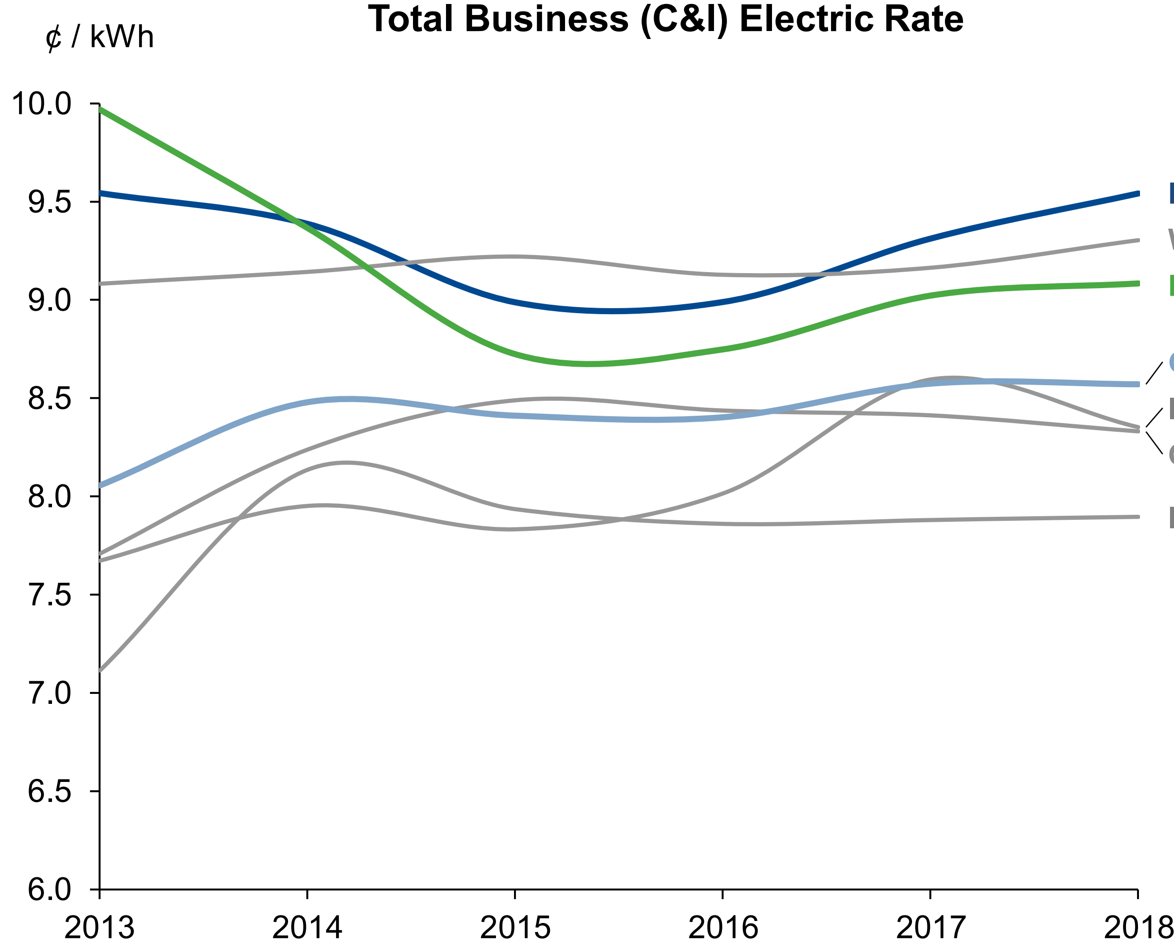
Source: EIA form 861M and 861

1. See page 16 for further details

DTE total business rate changes compare favorably to the regional average over 5 years but were higher over the 1 and 3 year periods

DTE Energy

Total Business (C&I) Electric Rate



Average annual growth

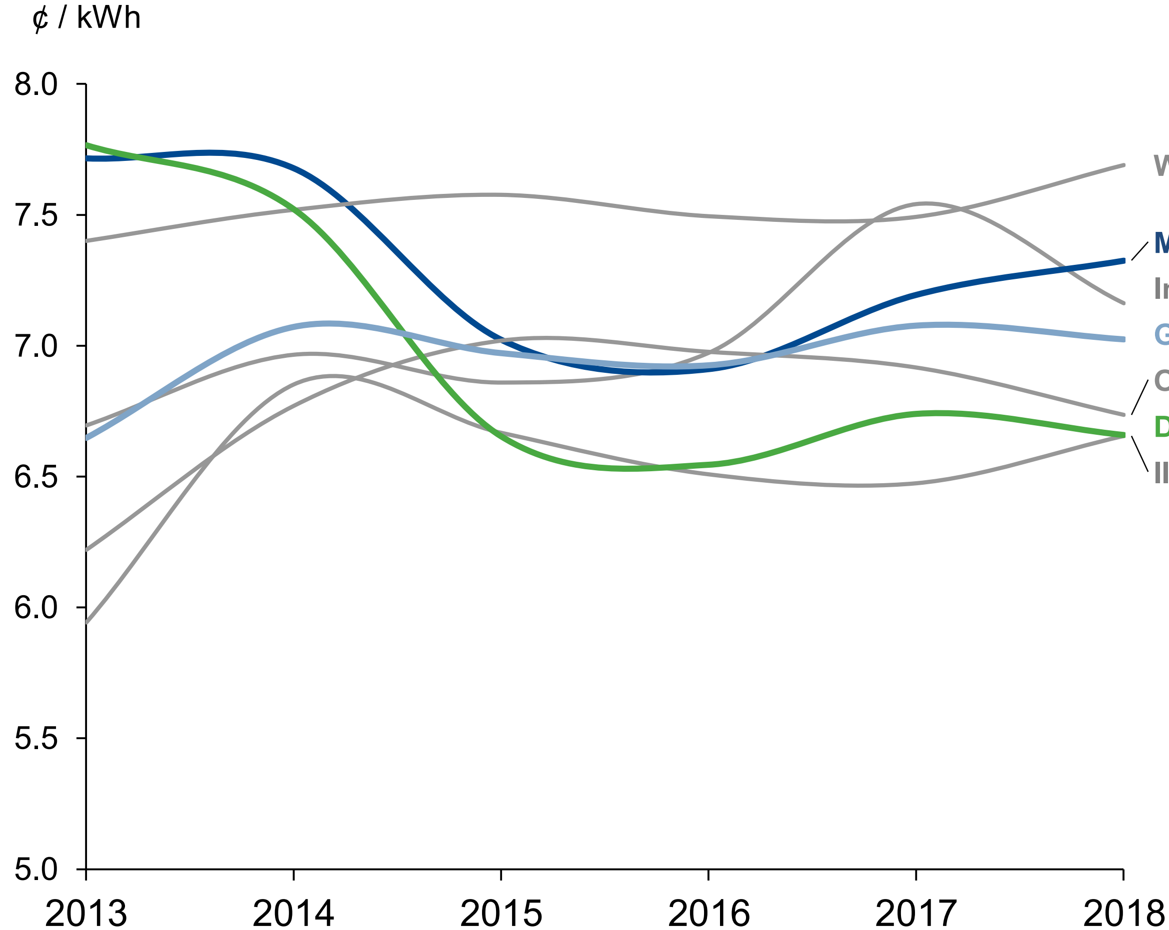
	1-year	3-year	5-year
Michigan	**2.5%**	**2.0%**	**0.0%**
Wisconsin	1.5%	0.3%	0.5%
DTE	**0.7%**	**1.4%**	**-1.8%**
Great Lakes avg.	**0.0%**	**0.6%**	**1.2%**
Indiana	-2.8%	2.2%	1.7%
Ohio	-1.0%	-0.6%	1.6%
Illinois	0.2%	-0.2%	2.1%

Source: EIA form 861M and 861

DTE industrial rates changes remain favorable compared to the regional average over the 1, 3 and 5 year periods

DTE Energy

Industrial Electric Rate



Average annual growth

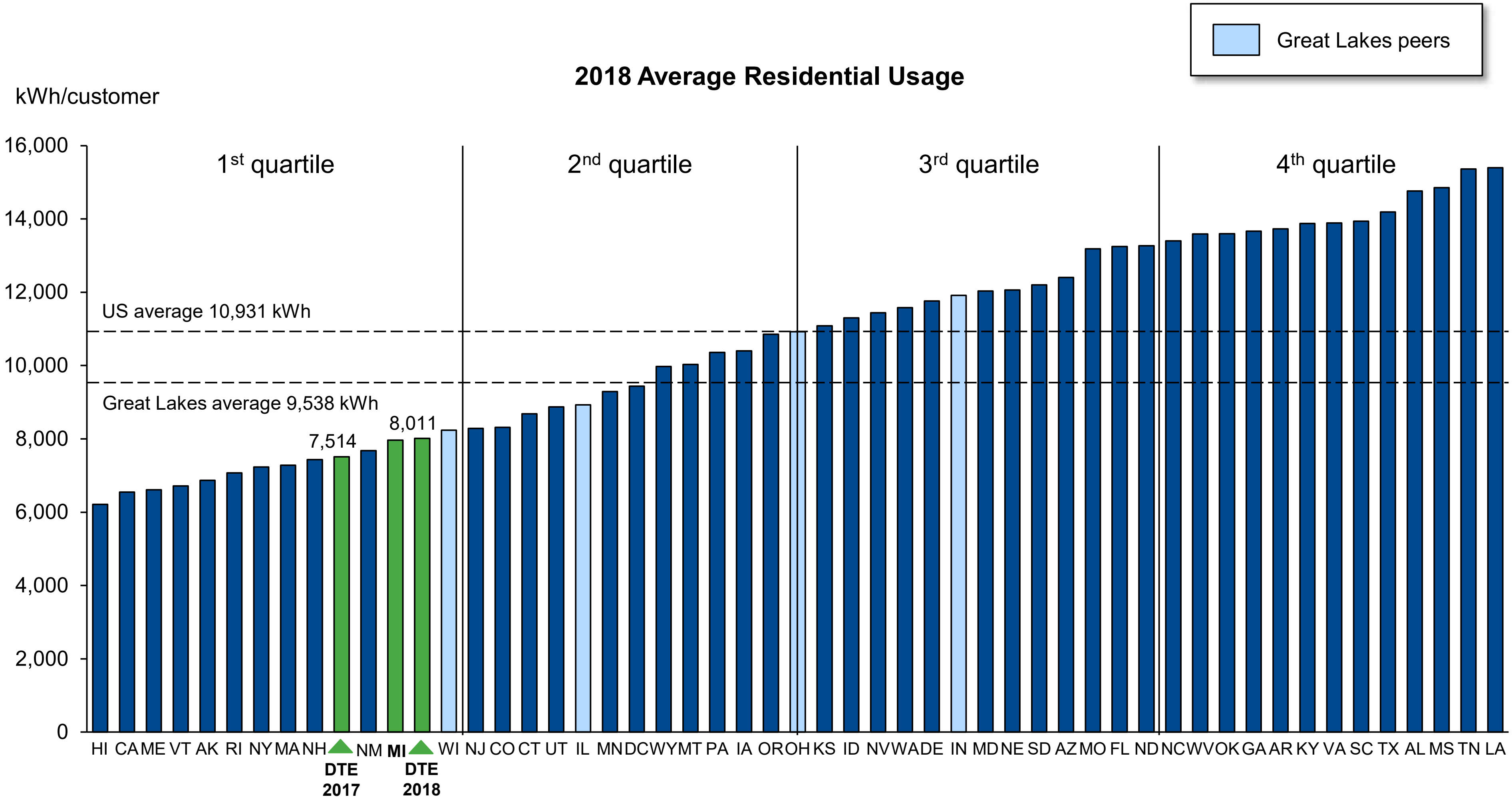
	1-year	3-year	5-year
Wisconsin	2.6%	0.5%	0.8%
Michigan	**1.8%**	**1.4%**	**-1.0%**
Indiana	-5.0%	1.4%	1.4%
Great Lakes avg.	**-0.7%**	**0.3%**	**1.1%**
Ohio	-2.6%	-1.4%	1.6%
DTE	**-1.2%**	**0.0%**	**-3.0%**
Illinois	2.8%	-0.1%	2.3%

Source: EIA form 861M and 861

DTE Spring 2019 Rate Benchmarking Study

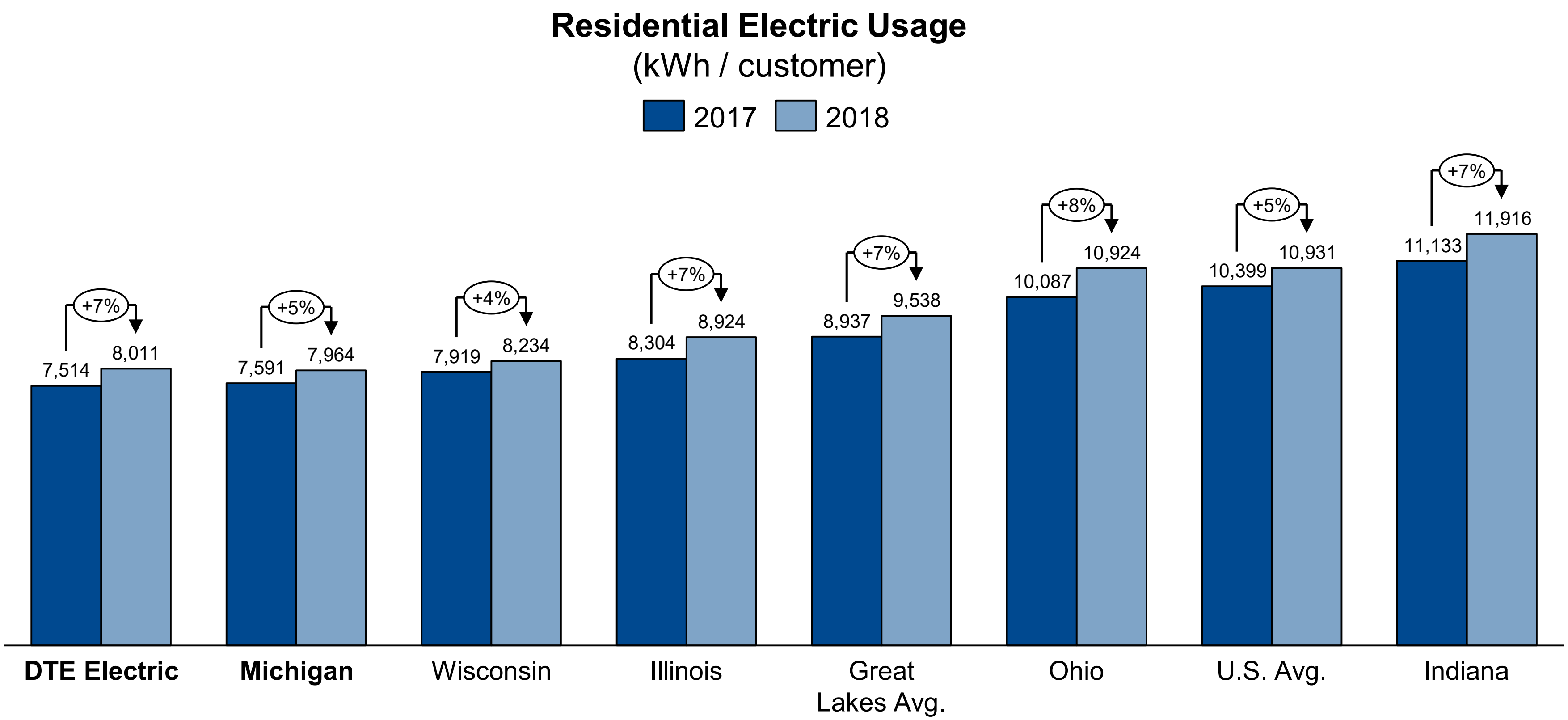
In 2018, DTE residential electric usage was 27% below the US average but increased by 7% year over year

DTE Energy



Source: EIA form 861M

In 2018, DTE saw a similar increase in average residential usage per customer compared to other Great Lakes states



This larger than Michigan average increase is attributed to DTE's higher sensitivity to abnormal temperature swings[1]

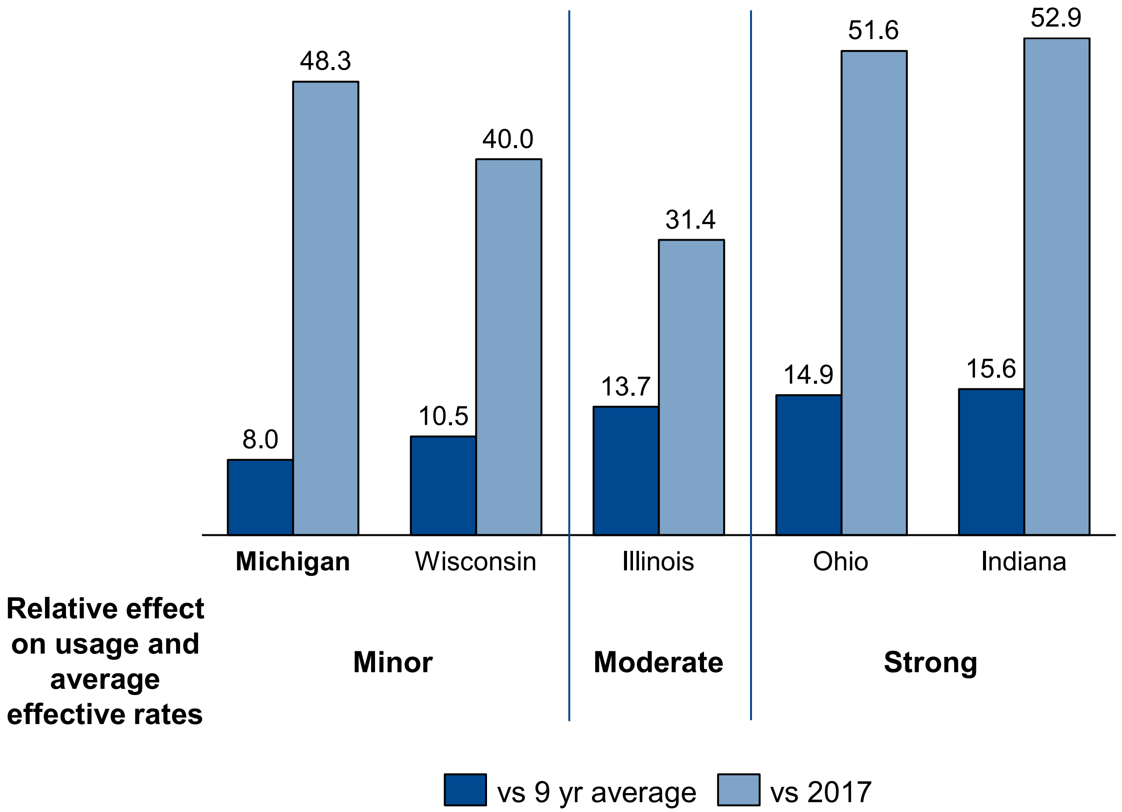
Source: EIA form 861 and 861M

1. DTE has higher A/C penetration and lower electric heat penetration than CMS which leads to more comparative usage in warm summers combined with less comparative usage in cold winters

A non-uniform 2018 increase in cooling degree days explains a majority of the state usage increases and effective residential rate behavior

DTE Energy

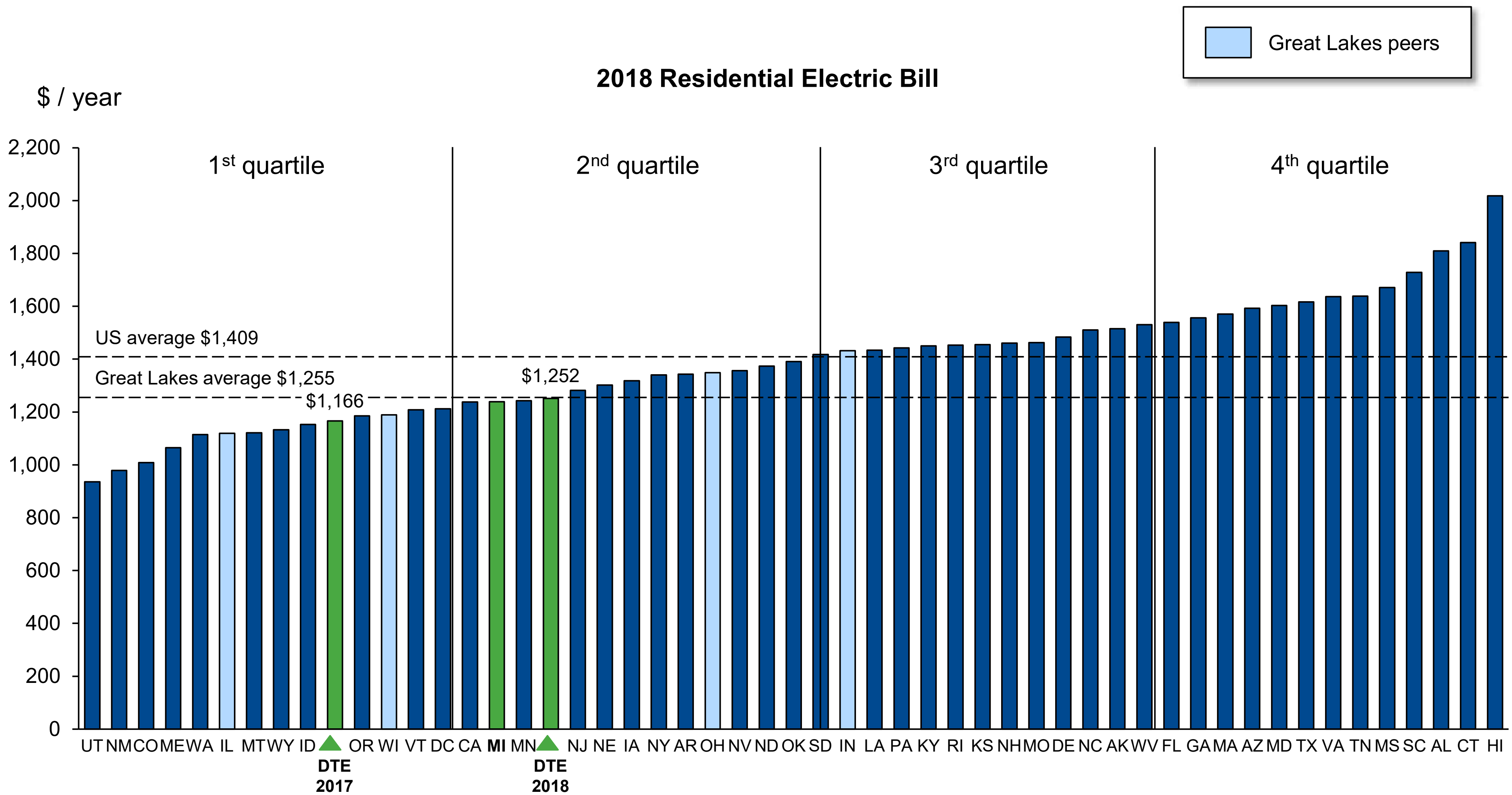
2018 Cooling degree days (CDDs) change by state (%)



Key insights

- The increase in CDDs across the region explain a majority of the residential electricity usage increases shown on the prior page
- Indiana, Ohio and Illinois saw significant increases in cooling degree days in 2018 relative to historical averages, causing significant usage increases relative to other regional states
- It is this increase relative to historical averages, and the associated increases in usage that has driven the decline in residential average effective rates in Indiana, Ohio and Illinois and the region as a whole (pages 10 & 11)

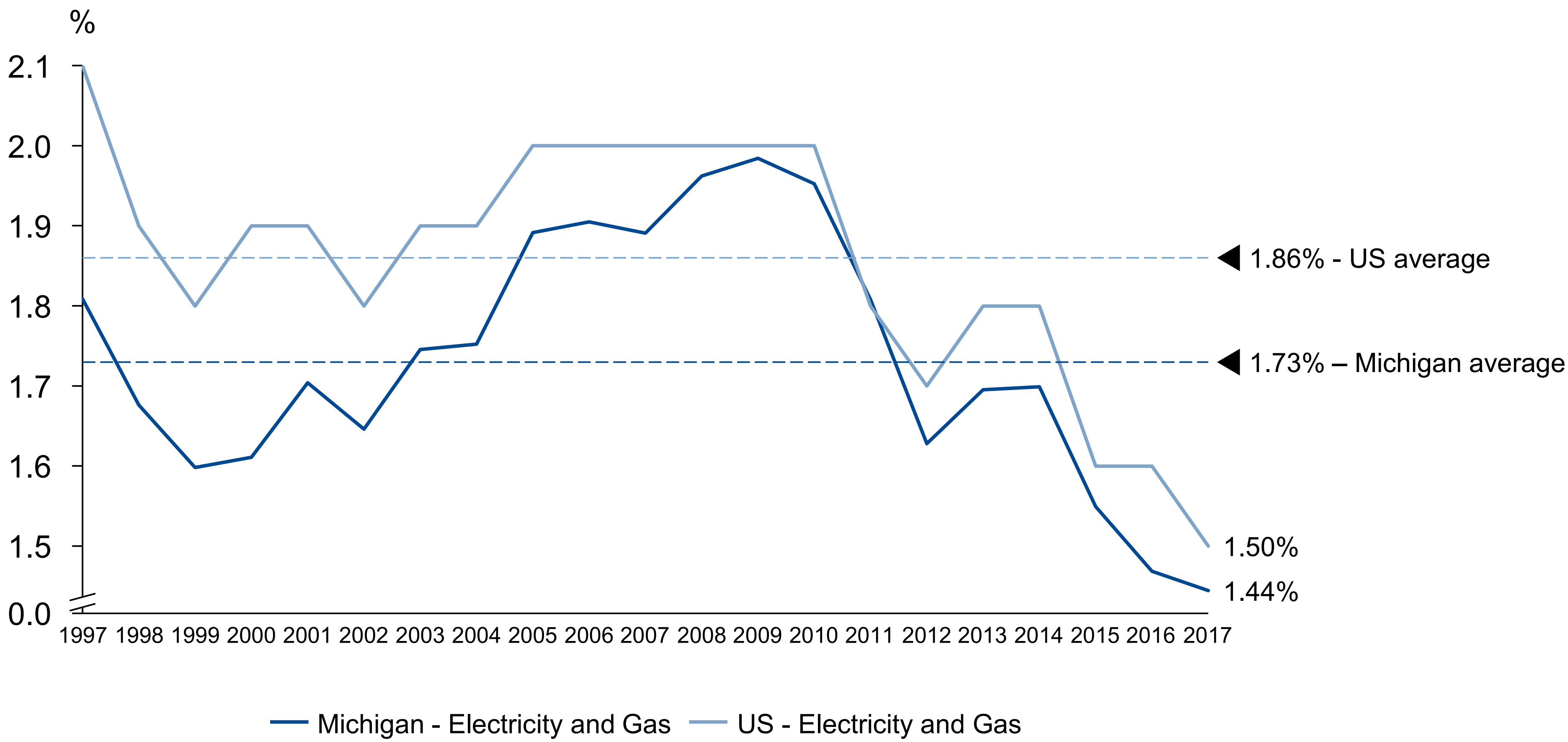
DTE average electric bills increased 7% from 2017 but remain 11% below the national average



Source: EIA form 861M

However, Michigan residential electric and gas utility expenditures are low relative to both the recent past and the national average

Michigan and US utility spending as a percent of disposable income over time

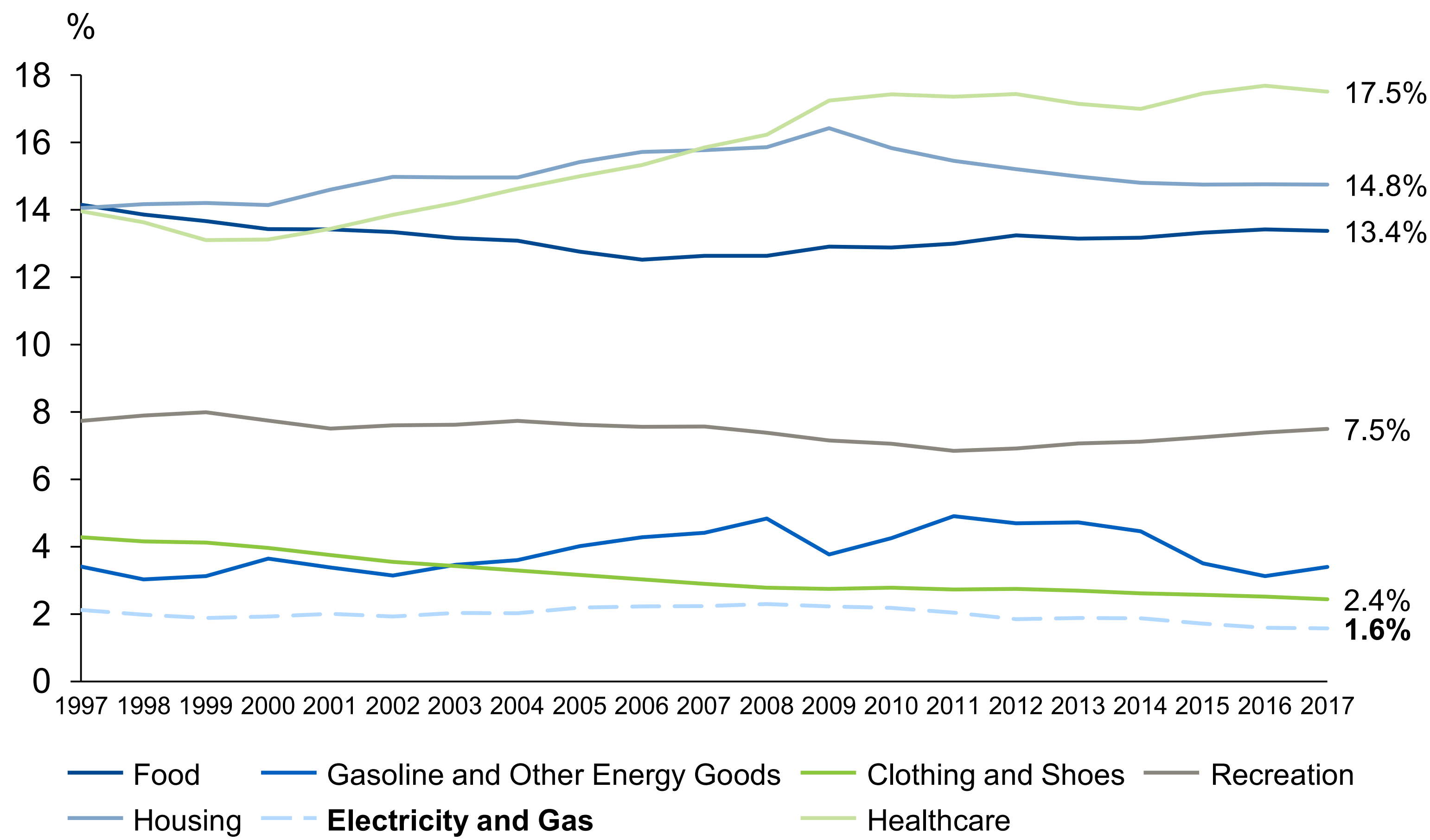


1. BEA SAINC1 Personal Income Summary: Personal Income, Population, Per Capita Personal Income

Within Michigan, residential electric and gas utility expenditures remain small relative to other typical categories of household spend

DTE Energy

Michigan personal consumption breakdown over time



1. BEA SAEXP1 Total personal consumption expenditures (PCE) by state (Michigan)

Spring 2021 Electric Rate and Bill Benchmarking – GRC Committee

May ??, 2021

Today we are sharing final 2020 benchmarking results for electric rates and bills

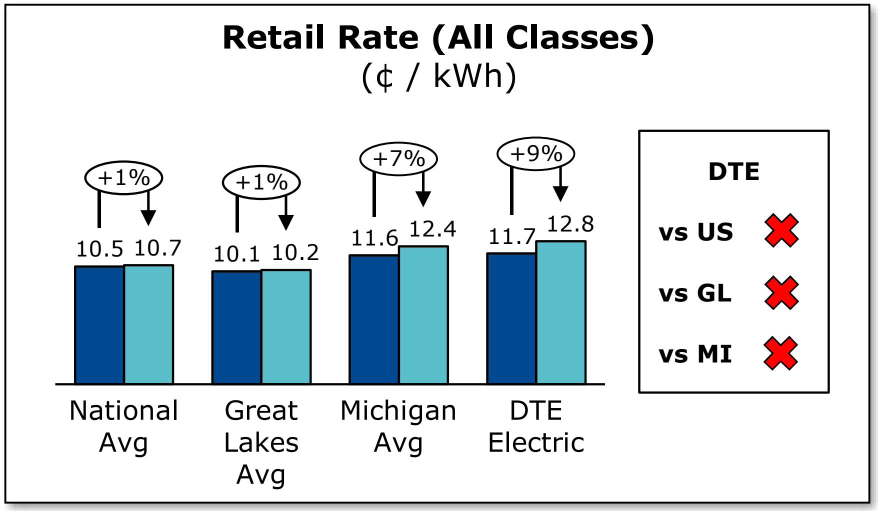
		Fall 2020 (Distributed 11/30/2020)	Spring 2021 (Today's update)
Rates	**Electric**	• 2020 through July (preliminary) • 2019 full year (final)	• 2020 full year (final)
Residential Bills	**Electric**	• 2019 full year (final)	• 2020 full year (final)
	Gas	• 2019 full year (final)	• NA

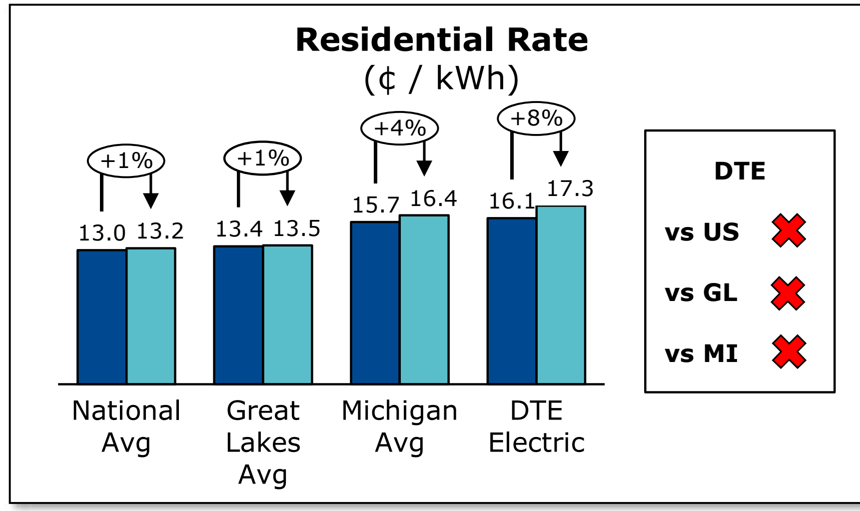
DTE

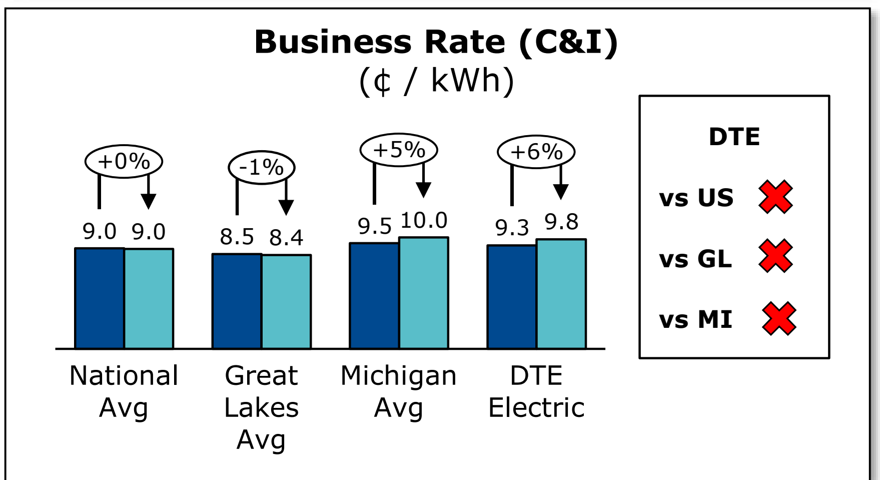
Note: Preliminary benchmarking refers to results based on the sum of monthly data (from EIA form 861M). Final data refers to results from reconciled full-year data (from EIA form 861 for electric and EIA Form 176 for gas)

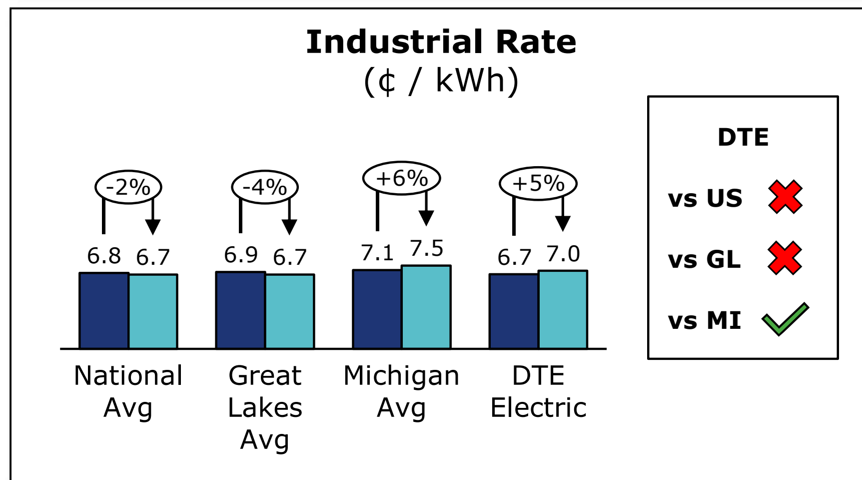
From 2019 to 2020, DTE Electric business rates increased while regional and national averages decreased or remained flat

2019
2020





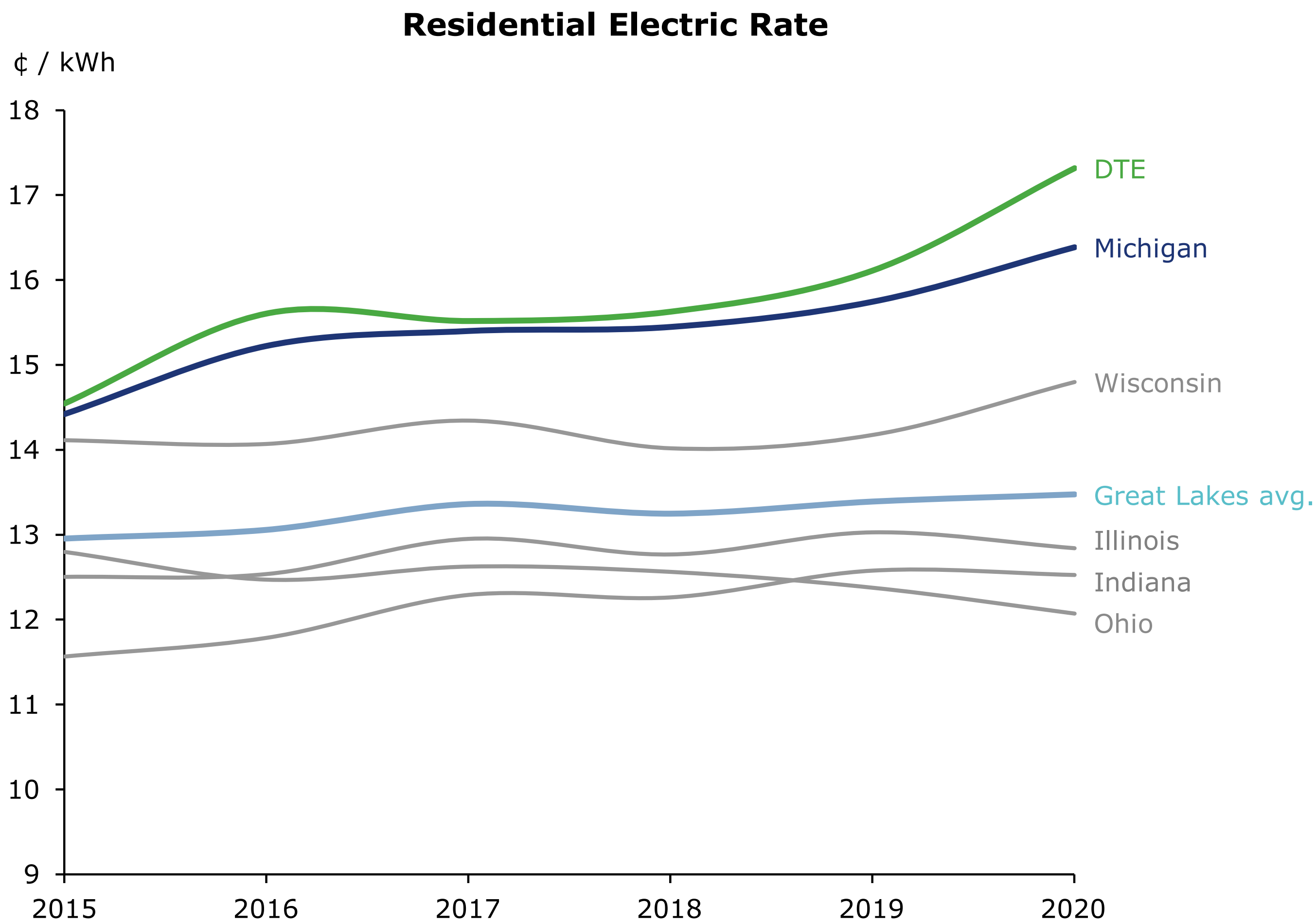




DTE

Source: EIA form 861 and 861M

Looking over the long-term, DTE and Michigan have the highest residential 5-year rate growth in the region



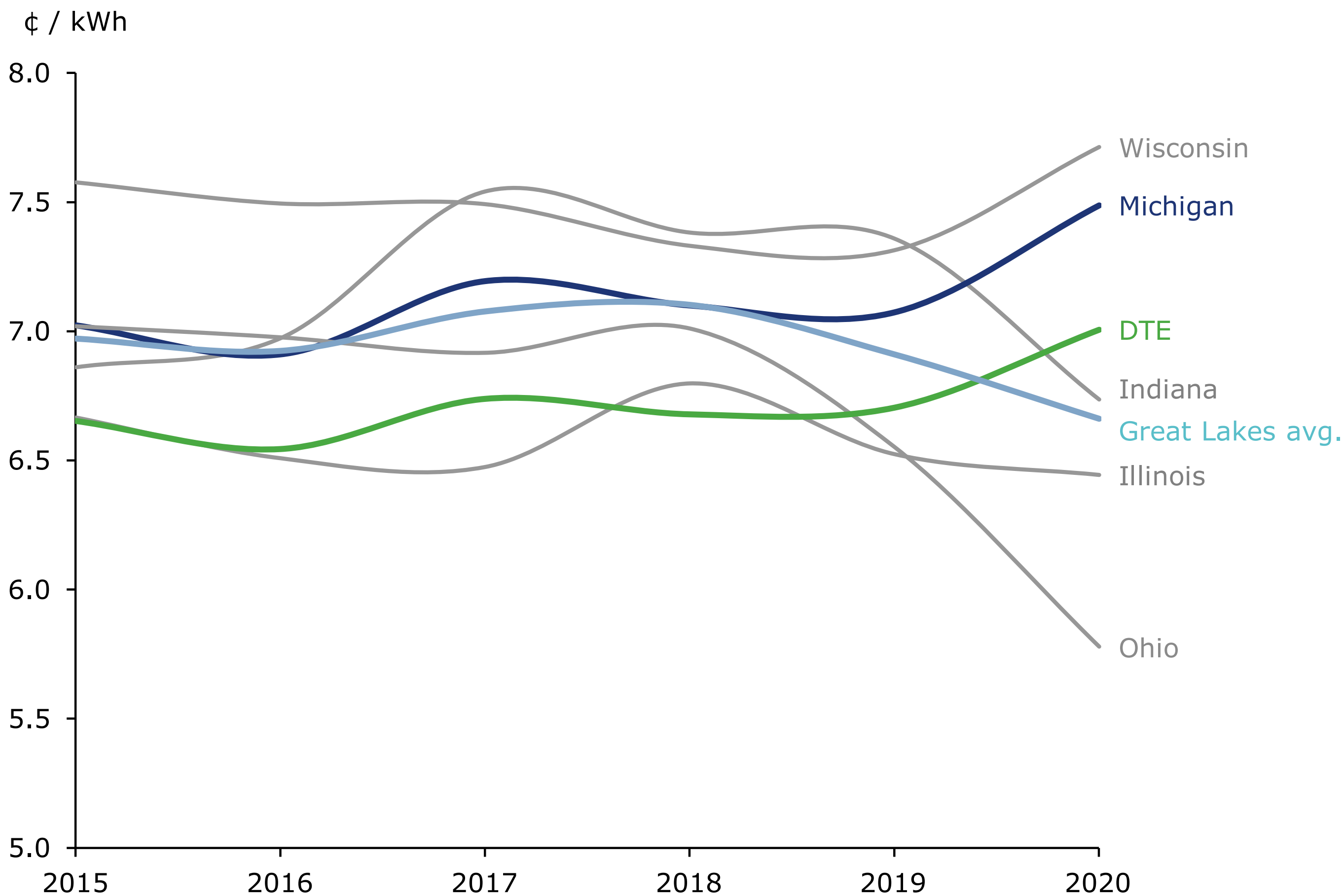
Average annual growth

	1-year	3-year	5-year
DTE	**7.5%**	**3.7%**	**3.5%**
Michigan	**4.1%**	**2.1%**	**2.6%**
Wisconsin	4.4%	1.0%	1.0%
Great Lakes avg.	**0.7%**	**0.3%**	**0.8%**
Illinois	-1.4%	-0.3%	0.5%
Indiana	-0.4%	0.6%	1.6%
Ohio	-2.5%	-1.5%	-1.2%

Source: EIA form 861M and 861

Michigan and DTE have the highest industrial rate growth over 5 years

Industrial Electric Rate



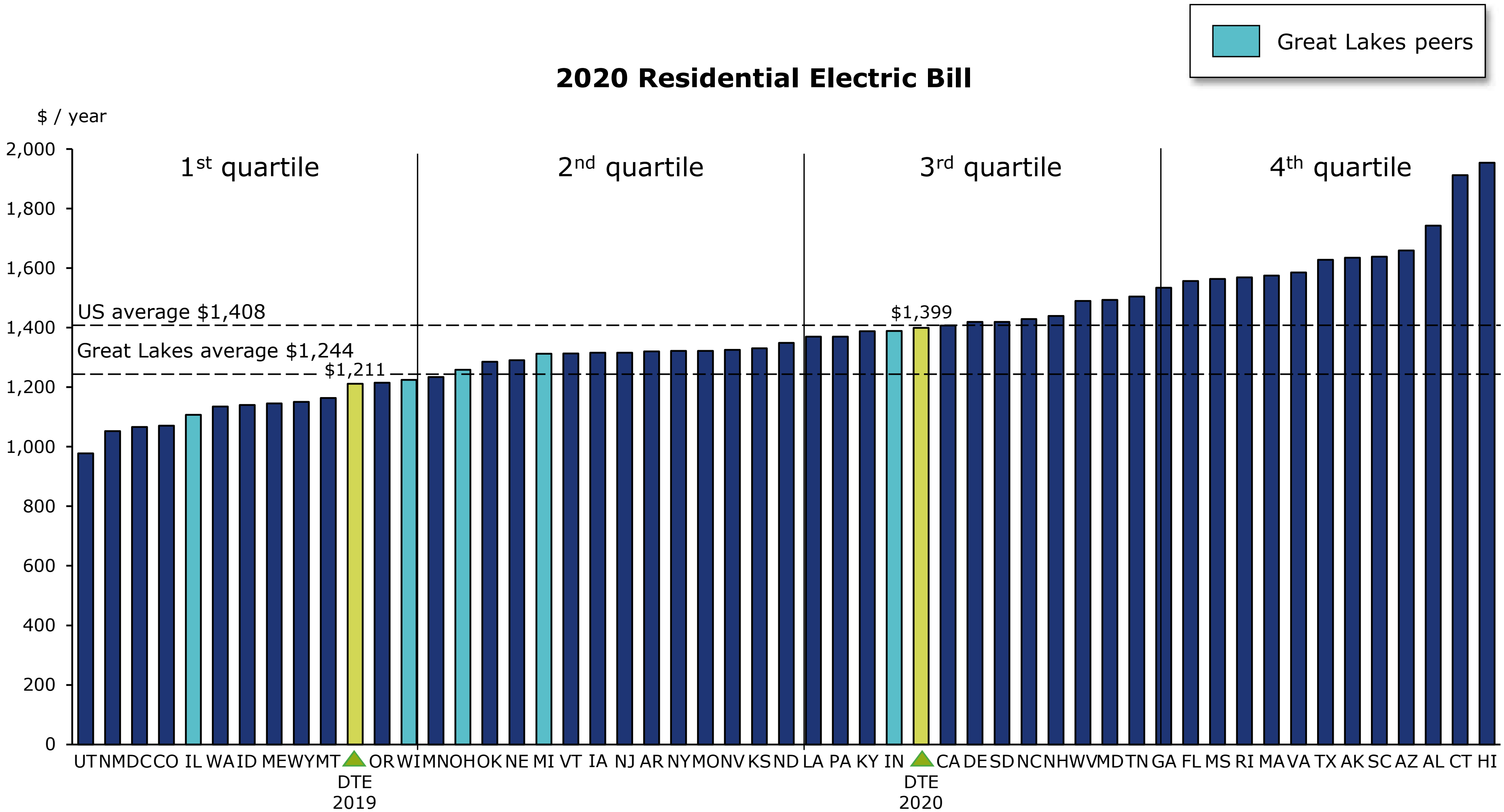
Average annual growth

	1-year	3-year	5-year
Wisconsin	5.5%	1.0%	0.4%
Michigan	**5.9%**	**1.3%**	**1.3%**
DTE	**4.5%**	**1.3%**	**1.0%**
Indiana	-8.5%	-3.7%	-0.4%
Great Lakes avg.	**-3.6%**	**-2.0%**	**-0.9%**
Illinois	-1.2%	-0.2%	-0.7%
Ohio	-11.8%	-5.8%	-3.8%

DTE

Source: EIA form 861M and 861

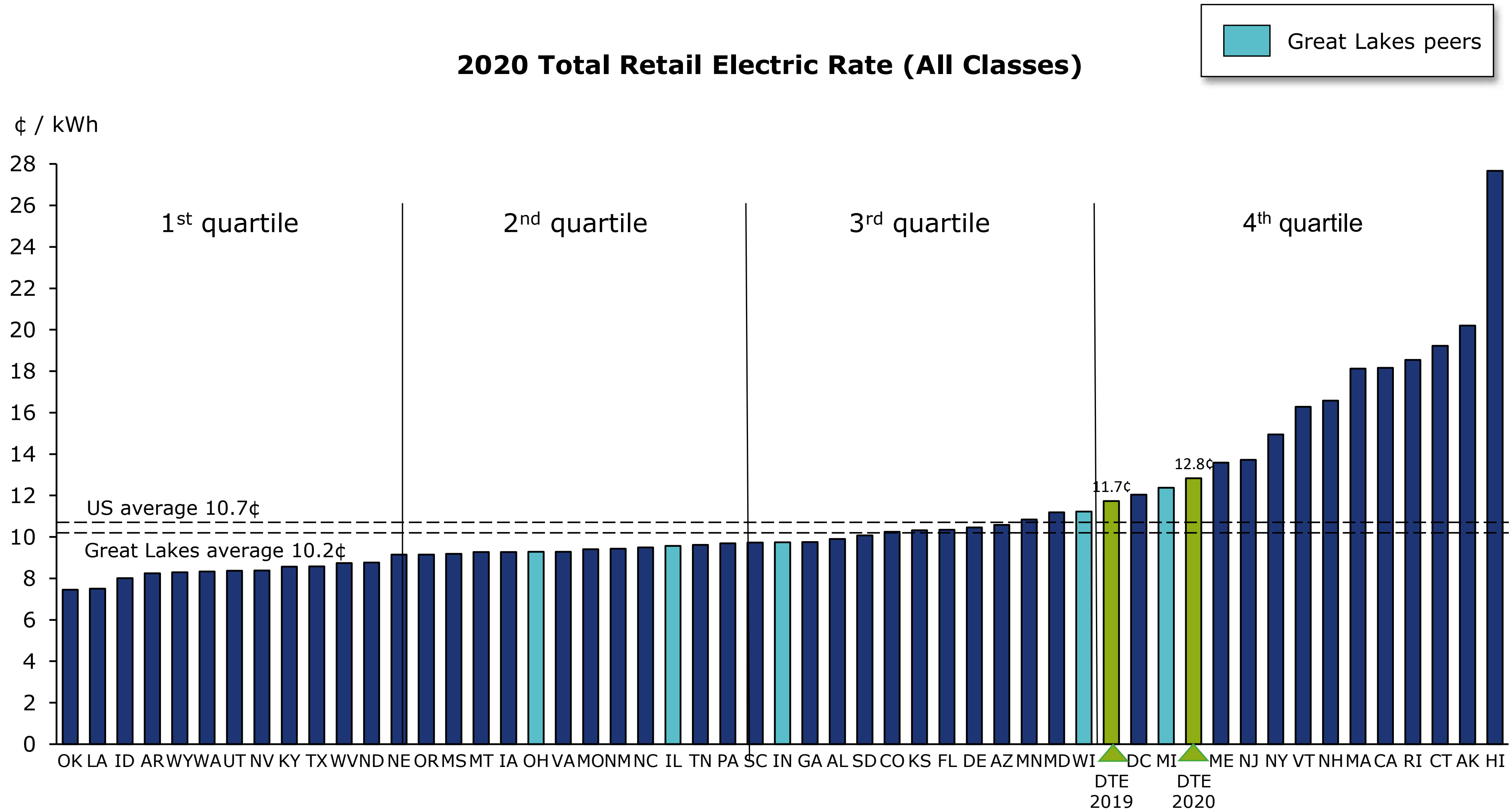
DTE average electric bills increased 15% from 2019 and moved into the 3rd quartile across the US



Source: EIA form 861M

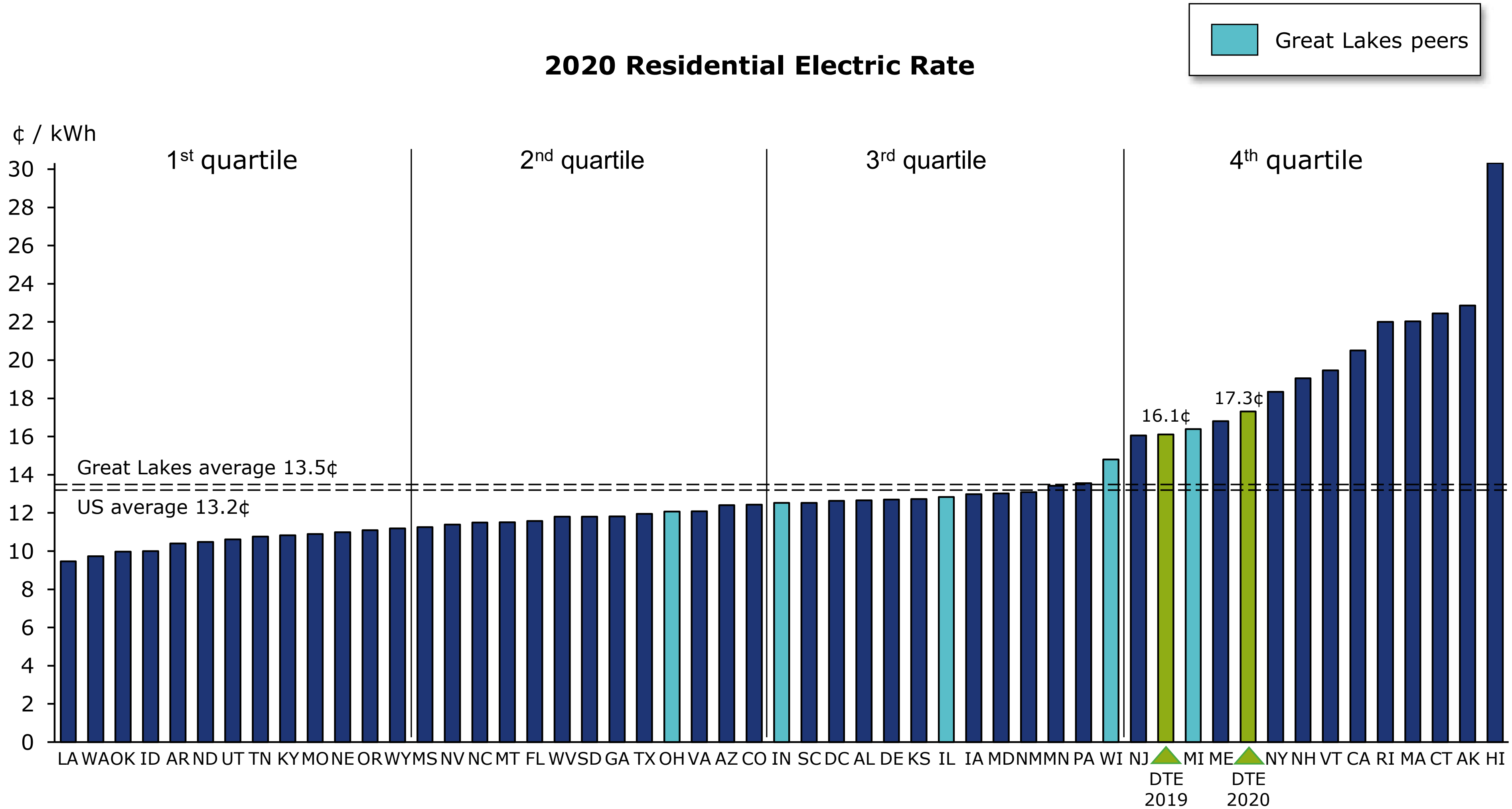
Appendix

In 2020, Michigan and DTE average total retail rates were 16% and 20%, respectively, above the US average and 21% and 25%, respectively, above the regional average



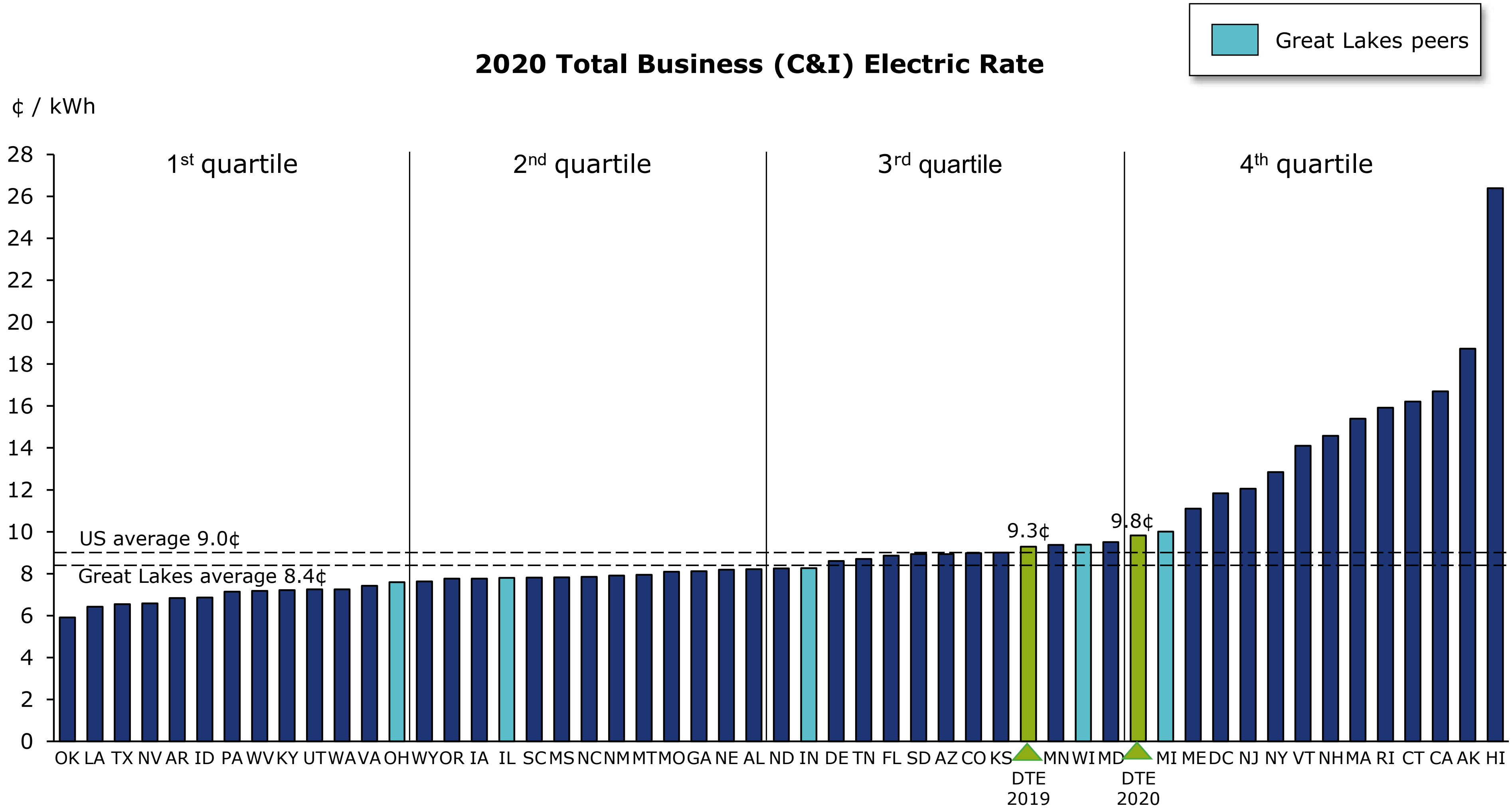
Source: EIA form 861M

Michigan and DTE average residential rates were 24% and 31% above the US average, respectively; and 22% and 28%, respectively, above the regional average



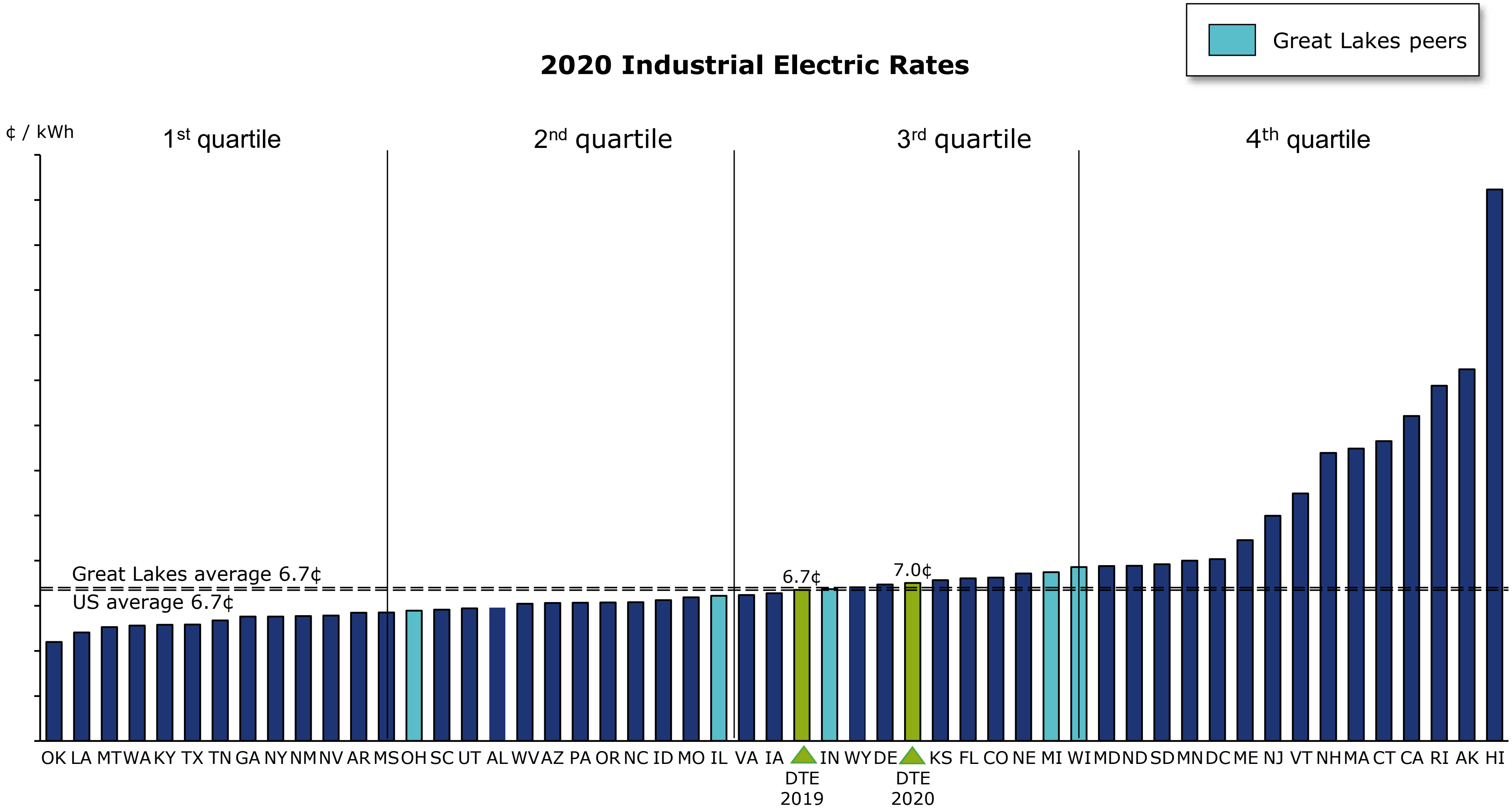
Source: EIA form 861M

Michigan and DTE average business rates were 11% and 9% above the US average, respectively; and 19% and 17%, respectively, above the regional average



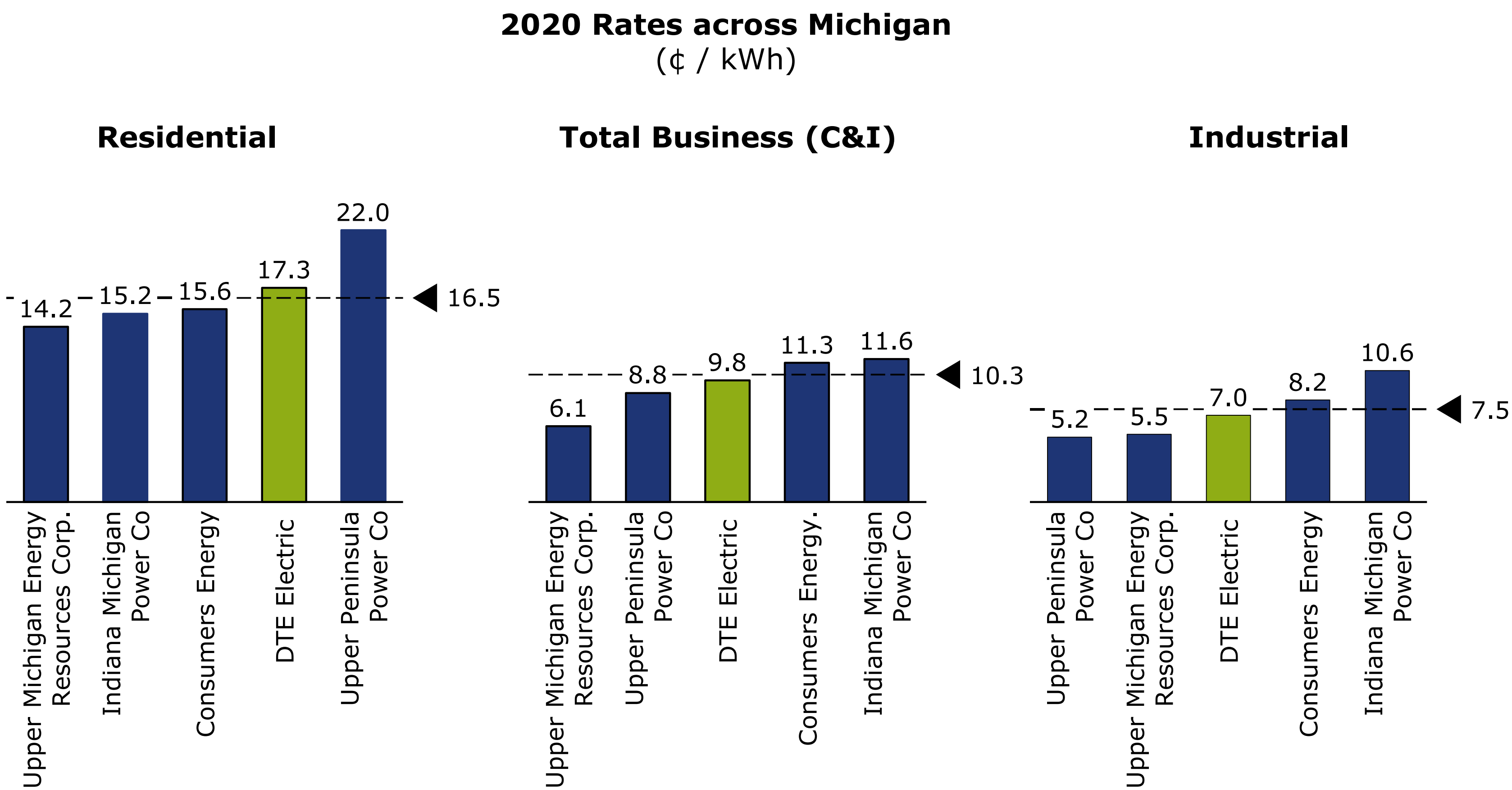
Source: EIA form 861M

Michigan average industrial rates were 12% above the US average while DTE industrial rates were 5% above the US and the region average



Source: EIA form 861M

DTE Electric's 2020 business and industrial rates were below the Michigan average

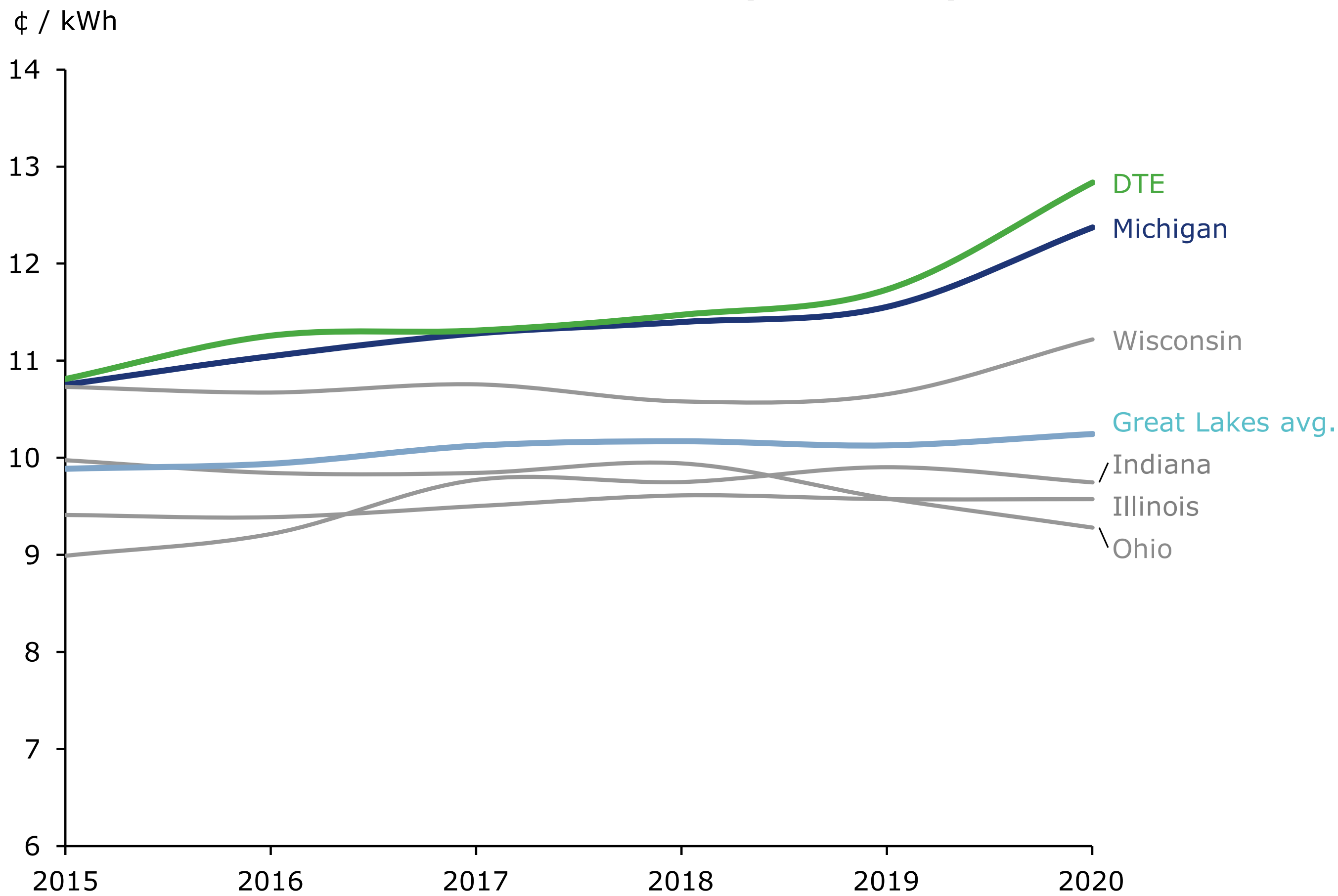


DTE business and industrial rates are below the Michigan average

Source: EIA form 861M

The changes in DTE Electric retail rates compare unfavorably to our regional average over the 1, 3, and 5 year period

Total Retail Electric Rate (All Classes)



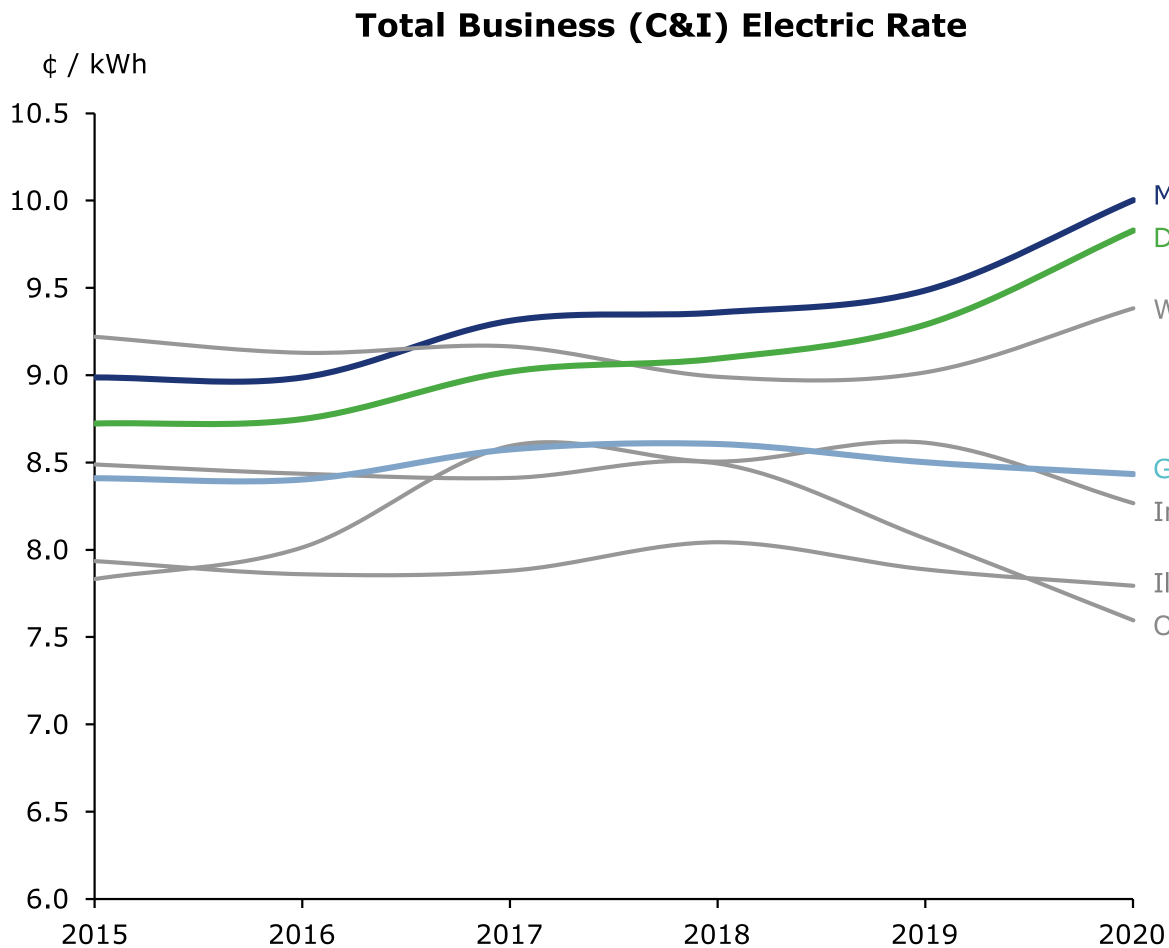
Average annual growth

	1-year	3-year	5-year
DTE	**9.4%**	**4.3%**	**3.5%**
Michigan	**7.1%**	**3.1%**	**2.8%**
Wisconsin	5.3%	1.4%	0.9%
Great Lakes avg.	**1.2%**	**0.4%**	**0.7%**
Indiana	-1.6%	-0.1%	1.6%
Illinois	0%	0.3%	0.3%
Ohio	-3.1%	-1.9%	-1.4%

DTE

Source: EIA form 861M and 861

DTE total business rate changes compare unfavorably to the regional average over 1, 3, and 5 year periods



Average annual growth

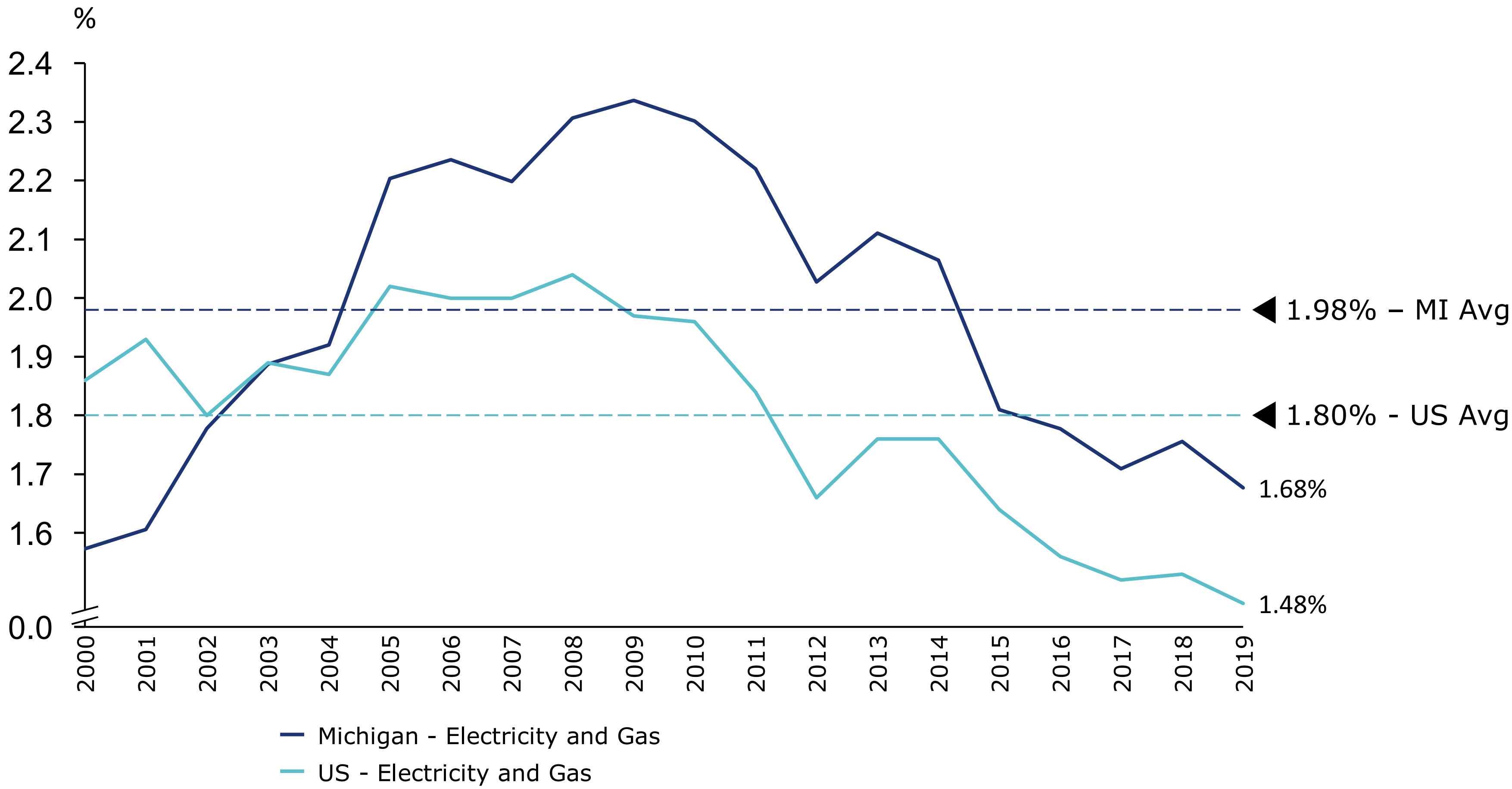
	1-year	3-year	5-year
Michigan	**5.4%**	**2.4%**	**2.2%**
DTE	**5.8%**	**2.9%**	**2.4%**
Wisconsin	4.1%	0.8%	0.4%
Great Lakes avg.	**-0.8%**	**-0.6%**	**0.1%**
Indiana	-4.0%	-1.3%	1.1%
Illinois	-1.2%	-0.4%	-0.4%
Ohio	-5.8%	-3.3%	-2.2%

DTE

Source: EIA form 861M and 861

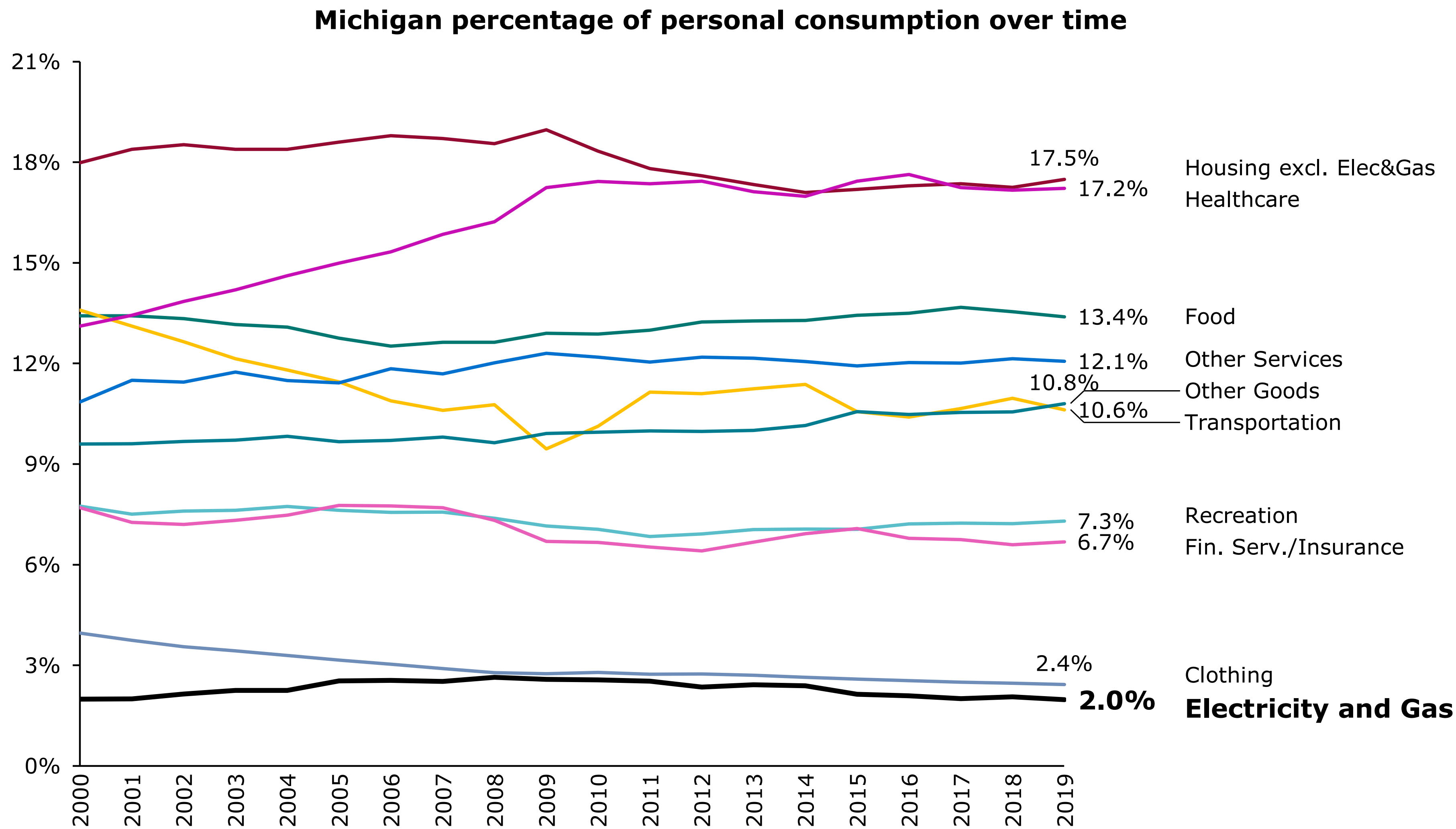
Michigan residential electric and gas utility expenditures are low relative to the recent past and have been tracking the national average

Michigan and US utility spending as a percent of disposable income over time



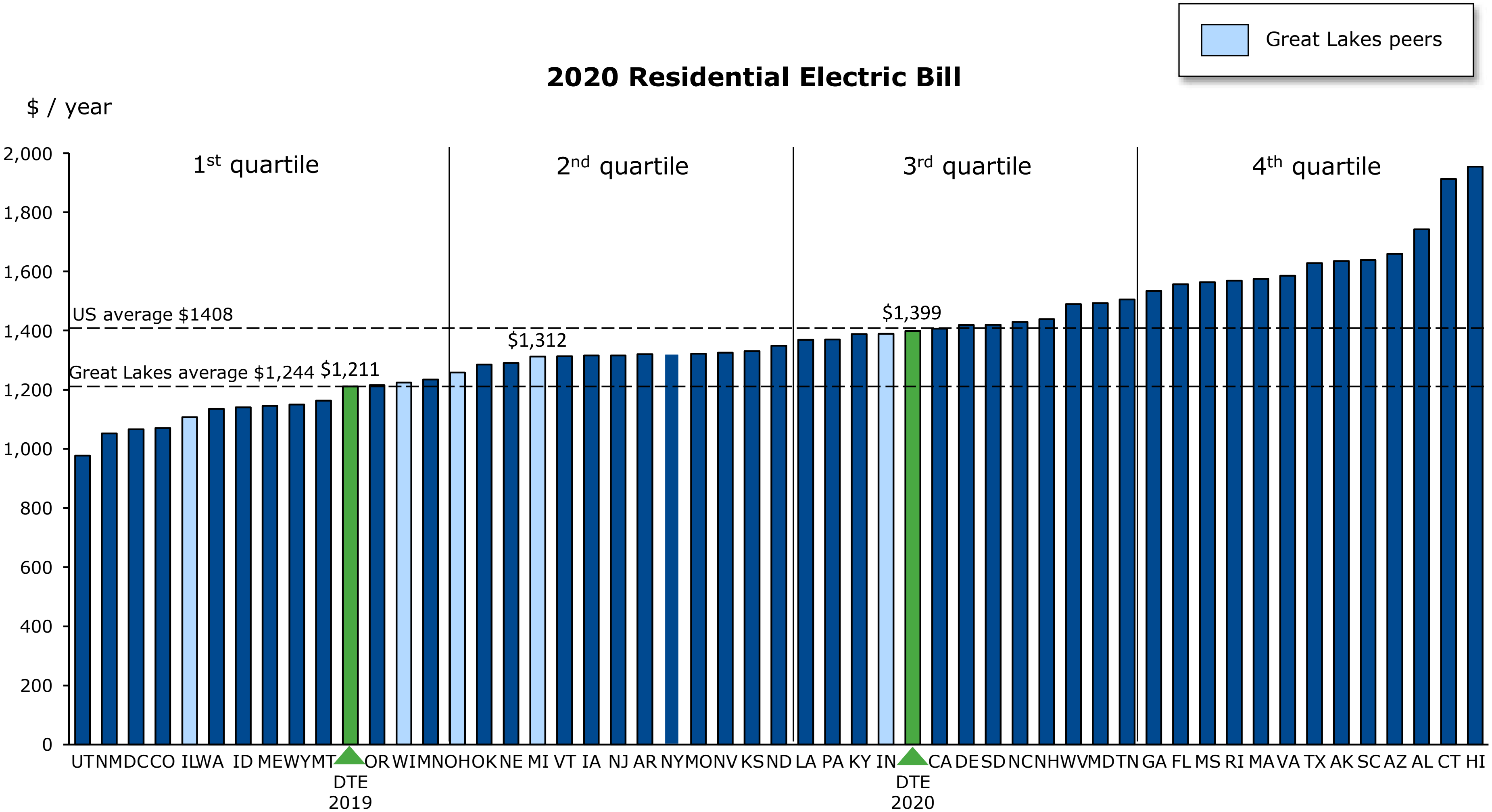
- BEA Table 2.1. and EIA
- BEA SAINC1 Personal Income Summary: Personal Income, Population, Per Capita Personal Income

Within Michigan, residential electric and gas utility expenditures remain small relative to other typical categories of household spend



Source: BEA SAEXP1 Total personal consumption expenditures (PCE) by state (Michigan), EIA for Electric and Gas

In 2020, DTE residential electric bills were 1% below and Michigan bills were 7% below the US average



DTE's Annual System Load Factor, 2017-2021

	2017	2018	2019	2020	2021
Total MWh Sold	42,322,880	43,789,344	42,072,635	40,629,492	41,481,966
Total Hours in Year	8,760	8,760	8,760	8,784	8,760
Avg. Demand Factor	**4,831**	**4,999**	**4,803**	**4,625**	**4,735**
4 CP Peak Demand	10,254	11,248	9,995	10,165	10,233
System Load Factor	**47.1%**	**44.4%**	**48.1%**	**45.5%**	**46.3%**

Source: FERC Form 1.

Alternative Analysis of Consumers' Electric Generation Units – 2021 Capacity Factors

Station Name	Plant Type	Nameplate Capacity (MW)	2021 Net Generation (MWh)	Capacity Factor	Allocation Energy	Allocation Demand	Plant in Service Energy ($000)	Plant in Service Demand ($000)	Plant in Service Total ($000)
Monroe	Steam	3,279.6	14,722,488	51.2%	51.2%	48.8%	$2,273,586	$2,163,064	$4,436,651
Fermi 2	Nuclear	1,217.0	9,369,535	87.9%	87.9%	12.1%	1,473,619	203,106	1,676,726
St. Clair PP	Steam	1,209.8	3,217,432	30.4%	30.4%	69.6%	279,940	642,151	922,091
Belle River DTE-81%	Steam	1,135.4	5,798,296	58.3%	58.3%	41.7%	1,137,446	813,654	1,951,101
Ludington (DTE%)	Hydro	1,036.0	1,095,455	12.1%	12.1%	87.9%	63,625	463,478	527,103
Greenwood EC	Steam	815.4	627,483	8.8%	0.0%	100.0%	-	420,093	420,093
Renaissance Peaker	Gas Turbine	782.0	744,873	10.9%	0.0%	100.0%	-	139,215	139,215
Trenton Channel PP	Steam	535.5	1,102,345	23.5%	23.5%	76.5%	94,519	307,701	402,220
River Rouge	Steam	358.1	17,092	0.5%	0.0%	100.0%	-	3,168	3,168
Dean Peaker	Gas Turbine	347.1	315,176	10.4%	0.0%	100.0%	-	146,320	146,320
Belle River Gas Pkr	Gas Turbine	256.0	158,214	7.1%	0.0%	100.0%	-	93,087	93,087
Greenwood Peaker	Gas Turbine	237.3	168,316	8.1%	0.0%	100.0%	-	80,612	80,612
Delray Peaker	Gas Turbine	154.3	22,009	1.6%	0.0%	100.0%	-	56,981	56,981
Northeast Peaker	Gas Turbine	129.9	10,225	0.9%	0.0%	100.0%	-	24,931	24,931
Hancock Peaker	Gas Turbine	121.5	14,042	1.3%	0.0%	100.0%	-	13,297	13,297
Enrico Fermi Peaker	Gas Turbine	64.0	167	0.0%	0.0%	100.0%	-	12,862	12,862
Superior Peaker	Gas Turbine	64.0	2,613	0.5%	0.0%	100.0%	-	11,078	11,078
Dearborn Energy Center	Combined Cycle	35.0	227,369	74.2%	74.2%	25.8%	-	-	0
St. Clair Peaker	Gas Turbine	18.6	2,956	1.8%	0.0%	100.0%	-	4,883	4,883
Belle River Oil Pkr	Internal Combustion	12.9	86	0.1%	0.0%	100.0%	-	3,408	3,408
Colfax Peaker	Internal Combustion	12.9	409	0.4%	0.0%	100.0%	-	2,085	2,085
Monroe Peaker	Internal Combustion	12.9	20	0.0%	0.0%	100.0%	-	1,650	1,650
Oliver Peaker	Internal Combustion	12.9	245	0.2%	0.0%	100.0%	-	2,171	2,171
Placid Peaker	Internal Combustion	12.9	5,630	5.0%	0.0%	100.0%	-	2,186	2,186
Putnam Peaker	Internal Combustion	12.9	1,130	1.0%	0.0%	100.0%	-	2,140	2,140
Slocum Peaker	Internal Combustion	12.9	25	0.0%	0.0%	100.0%	-	1,734	1,734
Wilmot Peaker	Internal Combustion	12.9	924	0.8%	0.0%	100.0%	-	1,986	1,986
River Rouge Peaker	Internal Combustion	10.3	325	0.4%	0.0%	100.0%	-	1,665	1,665
DTE Wind Facilities	Wind	1,236.8	-	-	100.0%	0.0%	2,367,222	-	2,367,222
DTE Solar Facilities	Solar	65.4	-	-	100.0%	0.0%	182,263	-	182,263
Subtotals:							**$7,872,221**	**$5,618,704**	**$13,490,925**
				Production Plant Classification:			**58.4%**	**41.6%**	**100.0%**

Note: Renewable Wind and Solar classified as 100 percent energy-related due to the intermittent nature of the resources.
Source: FERC Form 1.

Alternative Analysis of Consumers' Electric Generation Units – Levelized Cost

Station Name	Plant Type	Estimated Service Life	Nameplate Capacity (MW)	Total Plant in Service ($000)	Fixed Cost ($000/year)	Variable Costs ($000)	Levelized Cost ($/kW-year)	MISO CONE Zone 7 ($/MW-day)	MISO CONE Zone 7 ($/kW-year)	Allocation Energy	Allocation Demand	Plant in Service Energy ($000)	Plant in Service Demand ($000)	Plant in Service Total ($000)
Monroe	Steam	37.2	3,279.6	4,436,651	$ 119,112	$388,091	$ 155	$ 256.90	$ 93.77	39.37%	60.63%	$ 1,746,657	$ 2,689,994	$4,436,651
Fermi 2	Nuclear	32.2	1,217.0	1,676,726	52,061	$264,267	$ 260	256.90	93.77	63.92%	36.08%	1,071,841	604,884	1,676,726
St. Clair PP	Steam	21.9	1,209.8	922,091	42,188	$113,477	$ 129	256.90	93.77	27.12%	72.88%	250,112	671,979	922,091
Belle River DTE-81%	Steam	35.2	1,135.4	1,951,101	55,400	$147,541	$ 179	256.90	93.77	47.54%	52.46%	927,544	1,023,556	1,951,101
Ludington (DTE%)	Hydro	62.6	1,036.0	527,103	8,426	$47,225	$ 54	256.90	93.77	0.00%	100.00%	-	527,103	527,103
Greenwood EC	Steam	53.5	815.4	420,093	7,848	$42,504	$ 62	256.90	93.77	0.00%	100.00%	-	420,093	420,093
Renaissance Peaker	Gas Turbine	31.3	782.0	139,215	4,444	$39,339	$ 56	256.90	93.77	0.00%	100.00%	-	139,215	139,215
Trenton Channel PP	Steam	18.0	535.5	402,220	22,337	$49,705	$ 135	256.90	93.77	30.30%	69.70%	121,877	280,343	402,220
River Rouge	Steam	20.3	358.1	3,168	156	$5,974	$ 17	256.90	93.77	0.00%	100.00%	-	3,168	3,168
Dean Peaker	Gas Turbine	31.3	347.1	146,320	4,671	$18,881	$ 68	256.90	93.77	0.00%	100.00%	-	146,320	146,320
Belle River Gas Pkr	Gas Turbine	31.3	256.0	93,087	2,972	$9,672	$ 49	256.90	93.77	0.00%	100.00%	-	93,087	93,087
Greenwood Peaker	Gas Turbine	31.3	237.3	80,612	2,573	$10,478	$ 55	256.90	93.77	0.00%	100.00%	-	80,612	80,612
Delray Peaker	Gas Turbine	31.3	154.3	56,981	1,819	$1,557	$ 22	256.90	93.77	0.00%	100.00%	-	56,981	56,981
Northeast Peaker	Gas Turbine	31.3	129.9	24,931	796	$1,244	$ 16	256.90	93.77	0.00%	100.00%	-	24,931	24,931
Hancock Peaker	Gas Turbine	31.3	121.5	13,297	424	$1,136	$ 13	256.90	93.77	0.00%	100.00%	-	13,297	13,297
Enrico Fermi Peaker	Gas Turbine	31.3	64.0	12,862	411	$116	$ 8	256.90	93.77	0.00%	100.00%	-	12,862	12,862
Superior Peaker	Gas Turbine	31.3	64.0	11,078	354	$799	$ 18	256.90	93.77	0.00%	100.00%	-	11,078	11,078
Dearborn Energy Center	Combined Cycle	31.3	35.0	0	-	$11,018	$ 315	256.90	93.77	70.21%	29.79%	-	-	0
St. Clair Peaker	Gas Turbine	31.3	18.6	4,883	156	$198	$ 19	256.90	93.77	0.00%	100.00%	-	4,883	4,883
Belle River Oil Pkr	Internal Combustion	31.3	12.9	3,408	109	$77	$ 14	256.90	93.77	0.00%	100.00%	-	3,408	3,408
Colfax Peaker	Internal Combustion	31.3	12.9	2,085	67	$165	$ 18	256.90	93.77	0.00%	100.00%	-	2,085	2,085
Monroe Peaker	Internal Combustion	31.3	12.9	1,650	53	$103	$ 12	256.90	93.77	0.00%	100.00%	-	1,650	1,650
Oliver Peaker	Internal Combustion	31.3	12.9	2,171	69	$27	$ 7	256.90	93.77	0.00%	100.00%	-	2,171	2,171
Placid Peaker	Internal Combustion	31.3	12.9	2,186	70	$203	$ 21	256.90	93.77	0.00%	100.00%	-	2,186	2,186
Putnam Peaker	Internal Combustion	31.3	12.9	2,140	68	$244	$ 24	256.90	93.77	0.00%	100.00%	-	2,140	2,140
Slocum Peaker	Internal Combustion	31.3	12.9	1,734	55	$53	$ 8	256.90	93.77	0.00%	100.00%	-	1,734	1,734
Wilmot Peaker	Internal Combustion	31.3	12.9	1,986	63	$260	$ 25	256.90	93.77	0.00%	100.00%	-	1,986	1,986
River Rouge Peaker	Internal Combustion	31.3	10.3	1,665	53	$100	$ 15	256.90	93.77	0.00%	100.00%	-	1,665	1,665
DTE Wind Facilities	Wind	26.0	1,236.8	2,367,222	91,032	$26,139	$ 95	257.90	94.13	100.00%	0.00%	2,367,222	-	2,367,222
DTE Solar Facilities	Solar	26.0	65.4	182,263	7,010	$1,030	$ 123	258.90	94.50	100.00%	0.00%	182,263	-	182,263
Subtotals:												**$ 6,667,516**	**$ 6,823,409**	**$13,490,925**
										Production Plant Classification:		**49.4%**	**50.6%**	**100.0%**

Note: Renewable Wind and Solar classified as 100 percent energy-related due to the intermittent nature of the resources.
Source: FERC Form 1 and MISO 2022 PRA Results.

Witness Dismukes
Case No. 20836
Exhibit AG-2.6

Results of Alternative Class Cost of Service Study - Production and Distribution at Current Rates

	Total Electric ($000)						
Account Description	Total Electric	Total Residential Secondary	Total Commercial Secondary	Total Primary	Total Subtransmission	Total Transmission	Total Lighting
Total Company Revenues	$ 5,080,523	$ 2,628,095	$ 1,259,311	$ 1,099,122	$ 13,561	$ 11,624	$ 68,810
Total Expenses							
Fuel	$ 963,811	$ 401,486	$ 244,164	$ 313,365	$ -	$ -	$ 4,796
Purchased Power	395,929	155,709	91,790	146,932	-	-	1,498
Operating and Maintenance Expenses	1,280,715	734,866	298,749	225,801	3,846	4,228	13,226
Depreciation	1,087,914	588,430	288,035	173,075	4,149	3,009	31,217
Taxes Other than Income	356,311	194,051	93,772	56,935	2,038	1,706	7,809
Income Taxes	137,636	73,110	35,904	26,297	467	355	1,502
Total Company Expenses	$ 4,222,317	$ 2,147,652	$ 1,052,414	$ 942,405	$ 10,501	$ 9,298	$ 60,048
Net Operating Income	**$ 858,206**	**$ 480,443**	**$ 206,898**	**$ 156,717**	**$ 3,060**	**$ 2,325**	**$ 8,763**
Adjustments to Net Operating Income							
AFUDC and Other	$ 42,770	$ 19,423	$ 10,848	$ 12,366	$ -	$ -	$ 133
Net Adjustments	(1,777)	(927)	(471)	(335)	(9)	(8)	(27)
Total Adjustments to Net Operating Income	$ 40,993	$ 18,497	$ 10,377	$ 12,031	$ (9)	$ (8)	$ 106
Adjusted Net Operating Income	**$ 899,199**	**$ 498,939**	**$ 217,274**	**$ 168,748**	**$ 3,051**	**$ 2,318**	**$ 8,869**
Total Rate Base	**$ 21,267,942**	**$ 11,089,461**	**$ 5,641,076**	**$ 4,014,839**	**$ 109,962**	**$ 93,512**	**$ 319,092**
Return on Rate Base	**4.23%**	**4.50%**	**3.85%**	**4.20%**	**2.77%**	**2.48%**	**2.78%**
Relative Rate of Return	**1.00**	**1.06**	**0.91**	**0.99**	**0.66**	**0.59**	**0.66**

Results of Alternative Class Cost of Service Study - Production and Distribution at Current Rates

Account Description	Total Electric ($000) Total Electric	Total Residential Secondary	Total Commercial Secondary	Total Primary	Total Subtransmission	Total Transmission	Total Lighting
Required Income Under Company's Proposed ROR							
Total Rate Base	$ 21,267,942	$11,089,461	$ 5,641,076	$ 4,014,839	$ 109,962	$ 93,512	$ 319,092
Proposed Rate of Return (5.5560%)	5.5560%	5.5560%	5.5560%	5.5560%	5.5560%	5.5560%	5.5560%
Required Operating Income @ Proposed ROR	**$ 1,181,647**	**$ 616,130**	**$ 313,418**	**$ 223,064**	**$ 6,109**	**$ 5,196**	**$ 17,729**
Proposed Revenue Deficiency							
Required Operating Income	$ 1,181,647	$ 616,130	$ 313,418	$ 223,064	$ 6,109	$ 5,196	$ 17,729
Adjusted Net Operating Income	899,199	498,939	217,274	168,748	3,051	2,318	8,869
Operating Income Deficiency/(Surplus)	282,447	117,191	96,144	54,316	3,058	2,878	8,860
Revenue Conversion Factor	1.349635	1.349635	1.349635	1.349635	1.349635	1.349635	1.349635
Base Revenue Deficiency/(Surplus)	**$ 381,201**	**$ 158,165**	**$ 129,759**	**$ 73,307**	**$ 4,128**	**$ 3,884**	**$ 11,958**
Adjusted for Tree Trim Surge	7,021	4,513	2,166	276	0	0	65
Adjusted Revenue Deficiency/(Surplus)	**$ 388,222**	**$ 162,678**	**$ 131,925**	**$ 73,584**	**$ 4,128**	**$ 3,884**	**$ 12,023**
Proposed Revenue Requirement							
Present Rate Schedule Revenues	$ 5,080,523	2,628,095	1,259,311	1,099,122	13,561	11,624	68,810
Less Misc. Revenues	109,068	79,342	16,020	7,609	2,074	3,302	721
Plus Revenue Deficiency/(Surplus)	388,222	162,678	131,925	73,584	4,128	3,884	12,023
Proposed Revenue Requirement	**$ 5,359,677**	**$ 2,711,430**	**$ 1,375,216**	**$ 1,165,097**	**$ 15,615**	**$ 12,206**	**$ 80,112**
Total Proposed COS Revenue Increase (Decrease)	**$ 388,222**	**$ 162,678**	**$ 131,925**	**$ 73,584**	**$ 4,128**	**$ 3,884**	**$ 12,023**
Proposed Rate Increase (Decrease)	**7.64%**	**6.19%**	**10.48%**	**6.69%**	**30.44%**	**33.42%**	**17.47%**
Relative Proposed Rate Increase	**1.00**	**0.81**	**1.37**	**0.88**	**3.98**	**4.37**	**2.29**

Results of Company Class Cost of Service Study - Production and Distribution at Current Rates

	Total Electric ($000)						
Account Description	Total Electric	Total Residential Secondary	Total Commercial Secondary	Total Primary	Total Subtransmission	Total Transmission	Total Lighting
Total Company Revenues	$ 5,080,523	$ 2,628,500	$ 1,258,916	$ 1,099,122	$ 13,561	$ 11,624	$ 68,800
Total Expenses							
Fuel	$ 963,811	$ 401,486	$ 244,164	$ 313,365	$ -	$ -	$ 4,796
Purchased Power	395,929	155,709	91,790	146,932	-	-	1,498
Operating and Maintenance Expenses	1,280,715	741,052	292,823	225,801	3,846	4,228	12,965
Depreciation	1,087,914	609,337	279,076	161,994	4,149	3,009	30,349
Taxes Other than Income	356,311	199,797	90,909	54,298	2,038	1,706	7,563
Income Taxes	137,636	71,855	35,864	27,540	467	355	1,553
Total Company Expenses	$ 4,222,317	$ 2,179,236	$ 1,034,627	$ 929,931	$ 10,501	$ 9,298	$ 58,724
Net Operating Income	**$ 858,206**	**$ 449,264**	**$ 224,289**	**$ 169,192**	**$ 3,060**	**$ 2,325**	**$ 10,076**
Adjustments to Net Operating Income							
AFUDC and Other	$ 42,770	$ 20,472	$ 10,881	$ 11,327	$ -	$ -	$ 90
Net Adjustments	(1,777)	(959)	(460)	(315)	(9)	(8)	(25)
Total Adjustments to Net Operating Income	$ 40,993	$ 19,513	$ 10,421	$ 11,012	$ (9)	$ (8)	$ 65
Adjusted Net Operating Income	**$ 899,199**	**$ 468,777**	**$ 234,710**	**$ 180,203**	**$ 3,051**	**$ 2,318**	**$ 10,141**
Total Rate Base	**$ 21,267,944**	**$ 11,480,508**	**$ 5,504,476**	**$ 3,776,917**	**$ 109,962**	**$ 93,512**	**$ 302,570**
Return on Rate Base	**4.23%**	**4.08%**	**4.26%**	**4.77%**	**2.77%**	**2.48%**	**3.35%**
Relative Rate of Return	**1.00**	**0.97**	**1.01**	**1.13**	**0.66**	**0.59**	**0.79**

Results of Company Class Cost of Service Study - Production and Distribution at Current Rates

	Total Electric ($000)						
Account Description	**Total Electric**	**Total Residential Secondary**	**Total Commercial Secondary**	**Total Primary**	**Total Subtransmission**	**Total Transmission**	**Total Lighting**
Required Income Under Company's Proposed ROR							
Total Rate Base	$ 21,267,944	$11,480,508	$ 5,504,476	$ 3,776,917	$ 109,962	$ 93,512	$ 302,570
Proposed Rate of Return (5.5560%)	5.5560%	5.5560%	5.5560%	5.5560%	5.5560%	5.5560%	5.5560%
Required Operating Income @ Proposed ROR	**$ 1,181,647**	**$ 637,857**	**$ 305,829**	**$ 209,846**	**$ 6,109**	**$ 5,196**	**$ 16,811**
Proposed Revenue Deficiency							
Required Operating Income	$ 1,181,647	$ 637,857	$ 305,829	$ 209,846	$ 6,109	$ 5,196	$ 16,811
Adjusted Net Operating Income	899,199	468,777	234,710	180,203	3,051	2,318	10,141
Operating Income Deficiency/(Surplus)	282,448	169,080	71,119	29,642	3,058	2,878	6,670
Revenue Conversion Factor	1.349635	1.349635	1.349635	1.349635	1.349635	1.349635	1.349635
Base Revenue Deficiency/(Surplus)	**$ 381,201**	**$ 228,197**	**$ 95,984**	**$ 40,006**	**$ 4,128**	**$ 3,884**	**$ 9,002**
Adjusted for Tree Trim Surge	7,021	4,669	2,017	276	0	0	59
Adjusted Revenue Deficiency/(Surplus)	**$ 388,222**	**$ 232,866**	**$ 98,001**	**$ 40,283**	**$ 4,128**	**$ 3,884**	**$ 9,060**
Proposed Revenue Requirement							
Present Rate Schedule Revenues	$ 5,080,523	2,628,500	1,258,916	1,099,122	13,561	11,624	68,800
Less Misc. Revenues	109,068	79,747	15,625	7,609	2,074	3,302	711
Plus Revenue Deficiency/(Surplus)	388,222	232,866	98,001	40,283	4,128	3,884	9,060
Proposed Revenue Requirement	**$ 5,359,677**	**$ 2,781,618**	**$ 1,341,292**	**$ 1,131,796**	**$ 15,615**	**$ 12,206**	**$ 77,150**
Total Proposed COS Revenue Increase (Decrease)	**$ 388,222**	**$ 232,866**	**$ 98,001**	**$ 40,283**	**$ 4,128**	**$ 3,884**	**$ 9,060**
Proposed Rate Increase (Decrease)	**7.64%**	**8.86%**	**7.78%**	**3.66%**	**30.44%**	**33.42%**	**13.17%**
Relative Proposed Rate Increase	**1.00**	**1.16**	**1.02**	**0.48**	**3.98**	**4.37**	**1.72**

Results of Alternative Class Cost of Service Study - Capacity and Non-Capacity Revenues

Proposed Revenue Requirement	Production ($000) - Totals				
	Total Electric Service	Total Residential	Total Commercial Secondary	Total Primary	Total Lighting
Company Proposed					
Capacity Revenue Requirement	$1,285,101	$ 654,508	$ 328,171	$ 301,302	$ 1,120
Non-Capacity Revenue Requirement	$1,898,614	$ 725,680	$ 476,370	$ 686,003	$10,561
Total Power Supply Revenue Requirement	$3,183,715	$1,380,188	$ 804,541	$ 987,305	$11,681
Percent Capacity Revenue Requirement	**40.4%**	**47.4%**	**40.8%**	**30.5%**	**9.6%**
AG Proposed					
Capacity Revenue Requirement	$1,285,101	$ 654,508	$ 328,171	$ 301,302	$ 1,120
Non-Capacity Revenue Requirement	$1,898,614	$ 692,072	$ 475,317	$ 719,304	$11,922
Total Power Supply Revenue Requirement	$3,183,715	$1,346,580	$ 803,488	$1,020,606	$13,042
Percent Capacity Revenue Requirement	**40.4%**	**48.6%**	**40.8%**	**29.5%**	**8.6%**

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Residential Service Rate (D1)					
Distribution - Service Charge:	$ 7.50	$ 7.50	0.0%	$ 7.50	0.0%
Power Supply:					
Non-Capacity Charge	$ 0.04176	$ 0.04878	16.8%	$ 0.04639	11.1%
Capacity Charge - First 17 kWh/Day	$ 0.04500	$ 0.03862	-14.2%	$ 0.03862	-14.2%
Capacity Charge - Excess	$ 0.06484	$ 0.05564	-14.2%	$ 0.05564	-14.2%
Distribution:					
Distribution Charge	$ 0.06611	$ 0.08194	23.9%	$ 0.07951	20.3%
Residential - Interruptible Space-Conditioning Service Rate (D1.1)					
Distribution - Service Charge (June -October):	$ 1.95	$ 1.95	0.0%	$ 1.95	0.0%
Power Supply:					
Non-Capacity Charge	$ 0.03292	$ 0.03857	17.2%	$ 0.03668	11.4%
Capacity Charge - Summer	$ 0.04304	$ 0.03684	-14.4%	$ 0.03684	-14.4%
Capacity Charge - Winter	$ 0.01067	$ 0.00913	-14.4%	$ 0.00913	-14.4%
Distribution:					
Distribution Charge	$ 0.03292	$ 0.08194	148.9%	$ 0.07951	141.5%
Residential - Time of Day Service Rate (D1.2)					
Distribution - Service Charge:	$ 7.50	$ 7.50	0.0%	$ 7.50	0.0%
Power Supply:					
Non-Capacity Charge	$ 0.04261	$ 0.04735	11.1%	$ 0.04875	14.4%
Capacity Charge - Summer - On-Peak	$ 0.11841	$ 0.11248	-5.0%	$ 0.11412	-3.6%
Capacity Charge - Summer - Off-Peak	$ 0.01160	$ 0.00646	-44.3%	$ 0.00608	-47.6%
Capacity Charge - Winter - On-Peak	$ 0.09341	$ 0.08767	-6.1%	$ 0.08883	-4.9%
Capacity Charge - Winter - Off-Peak	$ 0.00948	$ 0.00435	-54.1%	$ 0.00394	-58.5%
Distribution:					
Distribution Charge	$ 0.06611	$ 0.08194	23.9%	$ 0.07951	20.3%

Comparison of Company and Alternative Proposed Rates

Description		Company's Present Rate		Company's Proposed Rate	Increase from Present Rate		Alternative Rates	Increase from Present Rate
Residential - Special Low Income Pilot Rate (D1.6)								
Distribution - Service Charge:	$	7.50	$	7.50	0.0%	$	7.50	0.0%
Power Supply:								
Non-Capacity Charge	$	0.04176	$	0.04878	16.8%	$	0.04639	11.1%
Capacity Charge - First 17 kWh/Day	$	0.04500	$	0.03862	-14.2%	$	0.03862	-14.2%
Capacity Charge - Excess	$	0.06484	$	0.05564	-14.2%	$	0.05564	-14.2%
Distribution:								
Distribution Charge	$	0.06611	$	0.08194	23.9%	$	0.07951	20.3%
Residential - Geothermal Time of Day Service Rate (D1.7)								
Distribution - Service Charge ($/day):	$	0.067	$	0.067	0.0%	$	0.067	0.0%
Power Supply:								
Non-Capacity Charge	$	0.02432	$	0.02879	18.4%	$	0.02738	12.6%
Capacity Charge - Summer - On-Peak	$	0.11595	$	0.11095	-4.3%	$	0.10879	-6.2%
Capacity Charge - Summer - Off-Peak	$	0.02214	$	0.01750	-21.0%	$	0.01772	-19.9%
Capacity Charge - Winter - On-Peak	$	0.03629	$	0.03160	-12.9%	$	0.03146	-13.3%
Capacity Charge - Winter - Off-Peak	$	0.02330	$	0.01865	-19.9%	$	0.01885	-19.1%
Distribution:								
Distribution Charge	$	0.06611	$	0.08194	23.9%	$	0.07951	20.3%
Residential - Dynamic Peak Pricing Rate (D1.8)								
Distribution - Service Charge:	$	7.50	$	7.50	0.0%	$	7.50	0.0%
Power Supply:								
Non-Capacity Charge	$	0.03576	$	0.04207	17.7%	$	0.04001	11.9%
Capacity Charge - Off-Peak (11 pm - 7am)	$	0.01218	$	0.01033	-15.2%	$	0.01032	-15.2%
Capacity Charge - Mid-Peak (7pm - 11pm, 7 am - 7 pm)	$	0.05645	$	0.04786	-15.2%	$	0.04785	-15.2%
Capacity Charge - On-Peak (3 pm - 7 pm)	$	0.13025	$	0.11042	-15.2%	$	0.11041	-15.2%
Capacity Charge - Critical Peak (3 pm - 7 pm)	$	0.91424	$	0.90793	-0.7%	$	0.90999	-0.5%
Distribution:								
Distribution Charge	$	0.06611	$	0.08194	23.9%	$	0.07951	20.3%

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Residential - Experimental Electric Vehiccle Rate (D1.9)					
Distribution - Option I Service Charge ($/month):	$ 1.95	$ 1.95	0.0%	$ 1.95	0.0%
Power Supply:					
Non-Capacity Charge - On-Peak	$ 0.07889	$ 0.09203	16.7%	$ 0.08752	10.9%
Non-Capacity Charge - Off-Peak	$ 0.01972	$ 0.02300	16.7%	$ 0.02188	10.9%
Capacity Charge - On-Peak	$ 0.09791	$ 0.08410	-14.1%	$ 0.08410	-14.1%
Capacity Charge - Off-Peak	$ 0.02448	$ 0.02103	-14.1%	$ 0.02103	-14.1%
Distribution:					
Distribution Charge	$ 0.06611	$ 0.08194	23.9%	$ 0.07951	20.3%
Residential - Space Heating Rate (D2)					
Distribution - Service Charge:	$ 7.50	$ 7.50	0.0%	$ 7.50	0.0%
Power Supply:					
Non-Capacity Charge	$ 0.04373	$ 0.04704	7.6%	$ 0.04896	12.0%
Capacity Charge - Summer - First 17 kWh/Day	$ 0.04624	$ 0.03662	-20.8%	$ 0.03662	-20.8%
Capacity Charge - Summer - Excess	$ 0.06613	$ 0.05238	-20.8%	$ 0.05238	-20.8%
Capacity Charge - Winter - First 20 kWh/Day	$ 0.02728	$ 0.02161	-20.8%	$ 0.02161	-20.8%
Capacity Charge - Winter - Excess	$ 0.01065	$ 0.00844	-20.8%	$ 0.00844	-20.8%
Distribution:					
Distribution Charge - Summer	$ 0.06611	$ 0.08194	23.9%	$ 0.07951	20.3%
Distribution Charge - Winter	$ 0.06611	$ 0.08194	23.9%	$ 0.07951	20.3%
Residential - Water Heating Service Rate (D5)					
Distribution - Service Charge:	$ 1.95	$ 1.95	0.0%	$ 1.95	0.0%
Power Supply:					
Non-Capacity Charge	$ 0.02228	$ 0.02599	16.6%	$ 0.02472	10.9%
Capacity Charge	$ 0.02765	$ 0.02375	-14.1%	$ 0.02375	-14.1%
Distribution:					
Distribution Charge	$ 0.06611	$ 0.08194	23.9%	$ 0.07951	20.3%

Comparison of Company and Alternative Proposed Rates

Description		Company's Present Rate		Company's Proposed Rate	Increase from Present Rate		Alternative Rates	Increase from Present Rate
Commercial - Interruptible Space Conditioning Service Rate (D1.1)								
Distribution - Service Charge (June - October):	$	1.95	$	1.95	-0.1%	$	1.95	-0.1%
Power Supply:								
Non-Capacity Charge	$	0.03749	$	0.04215	12.4%	$	0.04183	11.6%
Capacity Charge - Summer	$	0.04347	$	0.03662	-15.8%	$	0.03662	-15.8%
Capacity Charge - Winter	$	0.01044	$	0.01490	42.8%	$	0.01490	42.8%
Distribution:								
Distribution Charge	$	0.03749	$	0.04215	12.4%	$	0.04835	29.0%
Commercial - Geothermal Time of Day (D1.7)								
Distribution - Service Charge (June - October):	$	0.067	$	0.067	0.0%	$	0.067	0.0%
Power Supply:								
Non-Capacity Charge	$	0.02486	$	0.02801	12.7%	$	0.02780	11.8%
Capacity Charge - Summer (11 am Peak Start) - On-Peak	$	0.03447	$	0.03088	-10.4%	$	0.03088	-10.4%
Capacity Charge - Summer (11 am Peak Start) - Off-Peak	$	0.01792	$	0.01606	-10.4%	$	0.01606	-10.4%
Capacity Charge - Winter (11 am Peak Start) - On-Peak	$	0.02206	$	0.01976	-10.4%	$	0.01976	-10.4%
Capacity Charge - Winter (11 am Peak Start) - Off-Peak	$	0.02206	$	0.01976	-10.4%	$	0.01976	-10.4%
Distribution:								
Distribution Charge	$	0.03078	$	0.03848	25.0%	$	0.03848	25.0%
Commercial - Dynamic Peak Pricing Rate (D1.8)								
Distribution - Service Charge:	$	11.25	$	11.25	0.0%	$	11.25	0.0%
Power Supply:								
Non-Capacity Charge	$	0.04373	$	0.04387	0.3%	$	0.04354	-0.4%
Capacity Charge - Off-Peak (11 pm - 7 am)	$	0.00694	$	0.00721	3.9%	$	0.00721	3.9%
Capacity Charge - Mid-Peak (7 pm - 11 pm, 7 am - 3 pm)	$	0.04492	$	0.04665	3.9%	$	0.04665	3.9%
Capacity Charge - On-Peak (3 pm - 7 pm)	$	0.11005	$	0.11430	3.9%	$	0.11430	3.9%
Capacity Charge - Critical Peak (3 pm - 7 pm)	$	0.93013	$	1.22103	31.3%	$	1.22103	31.3%
Distribution:								
Distribution Charge	$	0.03868	$	0.04728	22.2%	$	0.04835	25.0%
Commercial - Experimental Electric Vehicle Rate (D1.9)								
Distribution - Option I Service Charge ($/month):	$	1.95	$	1.95	0.0%	$	1.95	0.0%
Power Supply:								
Non-Capacity Charge - On-Peak	$	0.07889	$	0.09203	16.7%	$	0.08752	10.9%
Non-Capacity Charge - Off-Peak	$	0.01972	$	0.02300	16.7%	$	0.02188	10.9%
Capacity Charge - On-Peak	$	0.09791	$	0.08410	-14.1%	$	0.08410	-14.1%
Capacity Charge - Off-Peak	$	0.02448	$	0.02103	-14.1%	$	0.02103	-14.1%
Distribution:								
Distribution Charge	$	0.06611	$	0.08194	23.9%	$	0.07951	20.3%

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Commercial - General Service Rate (D3)					
Distribution - Service Charge:	$ 11.25	$ 11.25	0.0%	$ 11.25	0.0%
Power Supply:					
Non-Capacity Charge	$ 0.04345	$ 0.04901	12.8%	$ 0.04864	11.9%
Capacity Charge	$ 0.03900	$ 0.03490	-10.5%	$ 0.03490	-10.5%
Distribution:					
Distribution Charge	$ 0.03868	$ 0.04728	22.2%	$ 0.04835	25.0%
Commercial - Unmetered General Service Rate (D3.1)					
Non-Capacity Charge	$ 0.07594	$ 0.08810	16.0%	$ 0.08034	5.8%
Capacity Charge	$ 0.03345	$ 0.02905	-13.1%	$ 0.02905	-13.1%
Commercial - Secondary Educational Institute (D3.2)					
Distribution - Service Charge:	$ 11.25	$ 11.25	0.0%	$ 11.25	0.0%
Power Supply:					
Non-Capacity Charge	$ 0.04356	$ 0.04815	10.5%	$ 0.04903	12.6%
Capacity Charge	$ 0.03002	$ 0.02877	-4.2%	$ 0.02877	-4.2%
Distribution:					
Distribution Charge	$ 0.03730	$ 0.04663	25.0%	$ 0.04663	25.0%
Commercial - Interruptible General Service Rate (D3.3)					
Distribution - Service Charge:	$ 11.25	$ 11.25	0.0%	$ 11.25	0.0%
Power Supply:					
Non-Capacity Charge	$ 0.03630	$ 0.04094	12.8%	$ 0.04063	11.9%
Capacity Charge	$ 0.03258	$ 0.02915	-10.5%	$ 0.02915	-10.5%
Distribution:					
Distribution Charge	$ 0.03868	$ 0.04728	22.2%	$ 0.04835	25.0%

Comparison of Company and Alternative Proposed Rates

Description		Company's Present Rate		Company's Proposed Rate	Increase from Present Rate		Alternative Rates	Increase from Present Rate
Commercial - Large General Service Rate (D4)								
Distribution - Service Charge:	$	13.67	$	13.67	0.0%	$	13.67	0.0%
Power Supply:								
Non-Capacity - Demand Charge	$	2.92	$	3.12	6.8%	$	3.12	6.8%
Non-Capacity - First 200 Hrs. use	$	0.04171	$	0.04583	9.9%	$	0.04677	12.1%
Non-Capacity - Excess	$	0.03219	$	0.03512	9.1%	$	0.03567	10.8%
Capacity - Demand Charge	$	14.07	$	12.27	-12.8%	$	12.27	-12.8%
Distribution:								
Distribution - Demand Charge	$	17.10	$	19.54	14.3%	$	24.35	42.4%
Commercial - Water Heating Service Rate (D5)								
Distribution - Service Charge:	$	1.95	$	1.95	0.0%	$	1.95	0.0%
Power Supply:								
Non-Capacity Charge	$	0.02558	$	0.02885	12.8%	$	0.02863	11.9%
Capacity Charge	$	0.02296	$	0.02054	-10.5%	$	0.02054	-10.5%
Distribution:								
Distribution Charge	$	0.03589	$	0.04486	25.0%	$	0.04486	25.0%
Commercial - Energy Only Street Lighting (E1.1)								
Power Supply:								
Non-Capacity Charge	$	0.03007	$	0.03384	12.5%	$	0.03358	11.7%
Capacity Charge - Secondary	$	0.02659	$	0.02385	-10.3%	$	0.02385	-10.3%
Capacity Charge - Dusk to Midnight	$	0.11621	$	0.10424	-10.3%	$	0.10424	-10.3%
Capacity Charge - Primary	$	0.02659	$	0.02385	-10.3%	$	0.02385	-10.3%
Distribution:								
Distribution Charge	$	0.03868	$	0.04728	22.2%	$	0.04835	25.0%
Commercial - Greenhouse Lighting Service Rate (R7)								
Distribution - Service Charge:	$	1.95	$	1.95	0.0%	$	1.95	0.0%
Power Supply:								
Non-Capacity Charge	$	0.02482	$	0.02800	12.8%	$	0.02778	11.9%
Capacity Charge	$	0.02228	$	0.01994	-10.5%	$	0.01994	-10.5%
Distribution:								
Distribution Charge	$	0.03868	$	0.04728	22.2%	$	0.04835	25.0%
Commercial - Space Conditioning Rate (R8)								
Distribution - Service Charge - R8 Separate Meter:	$	11.25	$	11.25	0.0%	$	11.25	0.0%
Distribution - Service Charge - R8a:	$	11.25	$	11.25	0.0%	$	11.25	0.0%
Power Supply:								
Non-Capacity Charge	$	0.03726	$	0.04284	15.0%	$	0.04252	14.1%
Capacity Charge - Summer June - October - R8 All KWH- Separate Meter	$	0.06040	$	0.05284	-12.5%	$	0.05284	-12.5%
Capacity Charge - Summer June - October - R8a initial Block of D3	$	0.03900	$	0.03490	-10.5%	$	0.03490	-10.5%
Capacity Charge - Summer June - October - R8a Excess	$	0.06040	$	0.05284	-12.5%	$	0.05284	-12.5%
Capacity Charge - Winter November - May - R8 First 1000 KWH- Sep Mtr	$	0.06040	$	0.05284	-12.5%	$	0.05284	-12.5%
Capacity Charge - Winter November - May - R8 Excess	$	0.02003	$	0.01752	-12.5%	$	0.01752	-12.5%
Capacity Charge - R8a initial Block of D3	$	0.03900	$	0.03490	-10.5%	$	0.03490	-10.5%
Capacity Charge - Excess	$	0.02003	$	0.01752	-12.5%	$	0.01752	-12.5%
Distribution:								
Distribution Charge	$	0.03868	$	0.04728	22.2%	$	0.04835	25.0%

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Primary - Primary Supply Rate (D11)					
Distribution - Service Charge - PV:	$ 70.00	$ 70.00	0.0%	$ 70.00	0.0%
Distribution - Service Charge - SV:	$ 375.00	$ 375.00	0.0%	$ 375.00	0.0%
Distribution - Service Charge - TV:	$ 375.00	$ 375.00	0.0%	$ 375.00	0.0%
Power Supply:					
Non-Capacity - Power Supply Demand	$ 3.30	$ 3.37	2.2%	$ 3.37	2.2%
Non-Capacity - Voltage Level Adjustment - Subtransmission	$ (0.11)	$ (0.06)	-45.7%	$ (0.06)	-45.7%
Non-Capacity - Voltage Level Adjustment - Transmission	$ (0.18)	$ (0.13)	-26.2%	$ (0.13)	-26.2%
Non-Capacity - Energy - On-Peak	$ 0.04261	$ 0.04676	9.7%	$ 0.04874	14.4%
Non-Capacity - Energy - Off-Peak	$ 0.03261	$ 0.03676	12.7%	$ 0.03874	18.8%
Non-Capacity - Voltage Discount - Subtransmission	$ (0.00113)	$ (0.00070)	-38.5%	$ (0.00073)	-35.4%
Non-Capacity - Voltage Discount - Transmission	$ (0.00191)	$ (0.00155)	-19.0%	$ (0.00163)	-14.9%
Capacity - Power Supply Demand	$ 13.82	$ 12.08	-12.6%	$ 12.08	-12.6%
Capacity - Voltage Discount - Subtransmission	$ (0.56)	$ (0.25)	-56.2%	$ (0.25)	-56.2%
Capacity - Voltage Discount - Transmission	$ (0.84)	$ (0.51)	-39.4%	$ (0.51)	-39.4%
Distribution:					
Distribution Charge - Primary	$ 4.21	$ 5.23	24.2%	$ 5.23	24.2%
Distribution Charge - Subtransmission	$ 1.65	$ 2.26	36.9%	$ 2.26	36.9%
Distribution Charge - Transmission	$ 0.70	$ 0.97	39.0%	$ 0.97	39.0%
Substation Credit:					
Demand	$ (0.30)	$ (0.30)	0.0%	$ (0.30)	0.0%
Energy	$ (0.00040)	$ (0.00040)	0.0%	$ (0.00040)	0.0%
Primary - Primary Educational Institute (D6.2)					
Distribution - Service Charge - PV:	$ 70.00	$ 70.00	0.0%	$ 70.00	0.0%
Distribution - Service Charge - SV:	$ 375.00	$ 375.00	0.0%	$ 375.00	0.0%
Distribution - Service Charge - TV:	$ 375.00	$ 375.00	0.0%	$ 375.00	0.0%
Power Supply:					
Non-Capacity - Energy - On-Peak	$ 0.04307	$ 0.04859	12.8%	$ 0.04875	13.2%
Non-Capacity - Energy - Off-Peak	$ 0.04007	$ 0.04559	13.8%	$ 0.04575	14.2%
Non-Capacity - Voltage Discount - Subtransmission	$ (0.00131)	$ (0.00082)	-37.3%	$ (0.00082)	-37.1%
Non-Capacity - Voltage Discount - Transmission	$ (0.00223)	$ (0.00183)	-18.0%	$ (0.00183)	-17.7%
Capacity - Power Supply Demand	$ 14.81	$ 12.16	-17.9%	$ 12.16	-17.9%
Capacity - Voltage Level Adjustment - Subtransmission	$ (0.60)	$ (0.25)	-58.8%	$ (0.25)	-58.8%
Capacity - Voltage Level Adjustment - Transmission	$ (0.90)	$ (0.51)	-43.1%	$ (0.51)	-43.1%
Distribution:					
Distribution Charge - Primary	$ 4.21	$ 5.23	24.2%	$ 5.23	24.2%
Distribution Charge - Subtransmission	$ 1.65	$ 2.26	36.9%	$ 2.26	36.9%
Distribution Charge - Transmission	$ 0.70	$ 0.97	39.0%	$ 0.97	39.0%
Substation Credit:					
Demand	$ (0.30)	$ (0.30)	0.0%	$ (0.30)	0.0%
Energy	$ (0.00040)	$ (0.00040)	0.0%	$ (0.00040)	0.0%

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Primary - Interruptible Supply Rate (D8)					
Distribution - Service Charge - PV:	$ 70.00	$ 70.00	0.0%	$ 70.00	0.0%
Distribution - Service Charge - SV:	$ 375.00	$ 375.00	0.0%	$ 375.00	0.0%
Distribution - Service Charge - TV:	$ 375.00	$ 375.00	0.0%	$ 375.00	0.0%
Power Supply:					
Non-Capacity - Power Supply Demand	$ 4.00	$ 3.17	-20.7%	$ 4.24	6.0%
Non-Capacity - Voltage Level Adjustment - Subtransmission	$ (0.13)	$ (0.06)	-56.8%	$ (0.08)	-42.3%
Non-Capacity - Voltage Level Adjustment - Transmission	$ (0.22)	$ (0.13)	-43.2%	$ (0.17)	-24.1%
Non-Capacity - Product Protection Demand	$ 3.30	$ 3.37	2.2%	$ 3.37	2.2%
Non-Capacity - Product Protection Demand - Voltage Discount - Subtransmission	$ (0.11)	$ (0.06)	-45.7%	$ (0.06)	-45.7%
Non-Capacity - Product Protection Demand - Voltage Discount - Tansmission	$ (0.18)	$ (0.13)	-26.2%	$ (0.13)	-26.2%
Non-Capacity - Energy - On-Peak	$ 0.04261	$ 0.04676	9.7%	$ 0.04874	14.4%
Non-Capacity - Energy - Off-Peak	$ 0.03261	$ 0.03676	12.7%	$ 0.03874	18.8%
Non-Capacity - Energy - Voltage Discount - Subtransmission	$ (0.00113)	$ (0.00070)	-38.5%	$ (0.00073)	-35.4%
Non-Capacity - Energy - Voltage Discount - Transmission	$ (0.00191)	$ (0.00155)	-19.0%	$ (0.00163)	-14.9%
Capacity - Power Supply Demand	$ 5.94	$ 5.41	-8.9%	$ 5.41	-8.9%
Capacity - Voltage Level Adjustment - Subtransmission	$ (0.24)	$ (0.11)	-54.2%	$ (0.11)	-54.2%
Capacity - Voltage Level Adjustment - Transmission	$ (0.36)	$ (0.23)	-36.6%	$ (0.23)	-36.6%
Capacity - Product Protection Demand	$ (0.36)	$ 12.08	-3456.3%	$ 12.08	-3456.3%
Capacity - Product Protection Demand - Voltage Level Adjustment - Subtransmission	$ (0.56)	$ (0.25)	-56.2%	$ (0.25)	-56.2%
Capacity - Product Protection Demand - Voltage Level Adjustment - Transmission	$ (0.84)	$ (0.51)	-39.4%	$ (0.51)	-39.4%
Distribution:					
Distribution Charge - Primary	$ 4.21	$ 5.23	24.2%	$ 5.23	24.2%
Distribution Charge - Subtransmission	$ 1.65	$ 2.26	36.9%	$ 2.26	36.9%
Distribution Charge - Transmission	$ 0.70	$ 0.97	39.0%	$ 0.97	39.0%
Distribution - Substation Credit - Demand	$ (0.30)	$ (0.30)	0.0%	$ (0.30)	0.0%
Distribution - Substation Credit - Energy	$ (0.00040)	$ (0.00040)	0.0%	$ (0.00040)	0.0%
Primary - All Electric School Building Rate (D10)					
Distribution - Service Charge:	$ 70.00	$ 70.00	0.0%	$ 70.00	0.0%
Power Supply:					
Non-Capacity Charge- Energy	$ 0.05070	$ 0.05572	9.9%	$ 0.05572	9.9%
Capacity Charge - Energy - Winter	$ 0.02442	$ 0.02133	-12.7%	$ 0.02375	-2.7%
Capacity Charge - Energy - Summer	$ 0.04455	$ 0.04146	-6.9%	$ 0.04388	-1.5%
Distribution:					
Distribution Charge - Primary	$ 0.01419	$ 0.01704	20.1%	$ 0.01704	20.1%

Comparison of Company and Alternative Proposed Rates

Description		Company's Present Rate		Company's Proposed Rate	Increase from Present Rate		Alternative Rates	Increase from Present Rate
Primary - Alternative Metal Melting Rider (R1.1)								
Power Supply:								
Non-Capacity - Energy	$	0.04394	$	0.04598	4.6%	$	0.05051	14.9%
Capacity - Energy - Secondary - First 100 Hours Use	$	0.02738	$	0.02520	-7.9%	$	0.02520	-7.9%
Capacity - Energy - Secondary - Excess Hours Use	$	0.01034	$	0.00952	-7.9%	$	0.00952	-7.9%
Capacity - Energy - Primary - First 100 Hours Use	$	0.02035	$	0.01873	-7.9%	$	0.01873	-7.9%
Capacity - Energy - Primary - Excess Hours Use	$	0.00743	$	0.00684	-7.9%	$	0.00684	-7.9%
Capacity - Energy - Subtransmission - First 100 Hours Use	$	0.01987	$	0.01829	-7.9%	$	0.01829	-7.9%
Capacity - Energy - Subtransmission - Excess Hours Use	$	0.00691	$	0.00636	-7.9%	$	0.00636	-7.9%
Capacity - Energy - Transmission - First 100 Hours Use	$	0.01685	$	0.01551	-7.9%	$	0.01551	-7.9%
Capacity - Energy - Transmission - Excess Hours Use	$	0.00558	$	0.00514	-7.9%	$	0.00514	-7.9%
Distribution:								
Distribution - Secondary - First 100 Hours Use	$	0.03223	$	0.04029	25.0%	$	0.04029	25.0%
Distribution - Secondary - Excess Hours Use	$	0.03223	$	0.04029	25.0%	$	0.04029	25.0%
Distribution - Primary - First 100 Hours Use	$	0.01231	$	0.01528	24.1%	$	0.01528	24.1%
Distribution - Primary - Excess Hours Use	$	0.01231	$	0.01528	24.1%	$	0.01528	24.1%
Distribution - Subtransmission - First 100 Hours Use	$	0.00541	$	0.00652	20.6%	$	0.00652	20.6%
Distribution - Subtransmission - Excess Hours Use	$	0.00541	$	0.00652	20.6%	$	0.00652	20.6%
Distribution - Transmission - First 100 Hours Use	$	0.00140	$	0.00211	50.6%	$	0.00211	50.6%
Distribution - Transmission - Excess Hours Use	$	0.00140	$	0.00211	50.6%	$	0.00211	50.6%
Distribution - Substation Credit - Energy	$	(0.00300)	$	(0.00300)	0.0%	$	(0.00300)	0.0%
Primary - Electric Process Heat Rider (R1.2)								
Power Supply:								
Non-Capacity - Energy	$	0.04394	$	0.04598	4.6%	$	0.05051	14.9%
Capacity - Energy - Secondary - First 100 Hours Use	$	0.02738	$	0.02520	-7.9%	$	0.02520	-7.9%
Capacity - Energy - Secondary - Excess Hours Use	$	0.01034	$	0.00952	-7.9%	$	0.00952	-7.9%
Capacity - Energy - Primary - First 100 Hours Use	$	0.02035	$	0.01873	-7.9%	$	0.01873	-7.9%
Capacity - Energy - Primary - Excess Hours Use	$	0.00743	$	0.00684	-7.9%	$	0.00684	-7.9%
Capacity - Energy - Subtransmission - First 100 Hours Use	$	0.01987	$	0.01829	-7.9%	$	0.01829	-7.9%
Capacity - Energy - Subtransmission - Excess Hours Use	$	0.00691	$	0.00636	-7.9%	$	0.00636	-7.9%
Capacity - Energy - Transmission - First 100 Hours Use	$	0.01685	$	0.01551	-7.9%	$	0.01551	-7.9%
Capacity - Energy - Transmission - Excess Hours Use	$	0.00558	$	0.00514	-7.9%	$	0.00514	-7.9%
Distribution:								
Distribution - Secondary - First 100 Hours Use	$	0.03223	$	0.04029	25.0%	$	0.04029	25.0%
Distribution - Secondary - Excess Hours Use	$	0.03223	$	0.04029	25.0%	$	0.04029	25.0%
Distribution - Primary - First 100 Hours Use	$	0.01231	$	0.01528	24.1%	$	0.01528	24.1%
Distribution - Primary - Excess Hours Use	$	0.01231	$	0.01528	24.1%	$	0.01528	24.1%
Distribution - Subtransmission - First 100 Hours Use	$	0.00541	$	0.00652	20.6%	$	0.00652	20.6%
Distribution - Subtransmission - Excess Hours Use	$	0.00541	$	0.00652	20.6%	$	0.00652	20.6%
Distribution - Transmission - First 100 Hours Use	$	0.00140	$	0.00211	50.6%	$	0.00211	50.6%
Distribution - Transmission - Excess Hours Use	$	0.00140	$	0.00211	50.6%	$	0.00211	50.6%
Distribution - Substation Credit - Energy	$	(0.00300)	$	(0.00300)	0.0%	$	(0.00300)	0.0%

Comparison of Company and Alternative Proposed Rates

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Primary - Parallel Operation and Standby Service Rider (R3)					
Distribution - Service Charge - Secondary:	$ 11.25	$ 70.00	522.2%	$ 70.00	522.2%
Distribution - Service Charge - PV:	$ 70.00	$ 70.00	0.0%	$ 70.00	0.0%
Distribution - Service Charge - SV:	$ 375.00	$ 375.00	0.0%	$ 375.00	0.0%
Distribution - Service Charge - TV:	$ 375.00	$ 375.00	0.0%	$ 375.00	0.0%
Power Supply:					
Non-Capacity - MISO Energy Charge	$ 0.02545	$ 0.02790	9.6%	$ 0.02790	9.6%
Non-Capacity - Net Trans MISO MKT Charge	$ 0.00740	$ 0.00756	2.2%	$ 0.00756	2.2%
Non-Capacity - Administrative Charge	$ 0.01676	$ 0.00775	-53.7%	$ 0.01102	-34.2%
Standard R3 Capacity - Power Supply Demand - Generation Reservation Fee	$ 0.50	$ 0.44	-12.8%	$ 0.44	-12.8%
Standard R3 Capacity - Power Supply Demand - Daily Demand	$ 1.38	$ 1.21	-12.4%	$ 1.21	-12.4%
Standard R3 Capacity - Power Supply Demand - Maintenance Demand	$ 0.69	$ 0.60	-12.4%	$ 0.60	-12.4%
Standard R3 Capacity - Energy - Secondary	$ 0.03900	$ 0.03490	-10.5%	$ 0.03490	-10.5%
Non-Capacity - Power Supply Demand - Generation Reservation Fee	$ 0.12	$ 0.12	1.5%	$ 0.12	1.5%
Non-Capacity- Power Supply Demand - Daily Demand	$ 0.33	$ 0.34	2.2%	$ 0.34	2.2%
Non-Capacity - Power Supply Demand - Maintenance Demand	$ 0.17	$ 0.17	-0.8%	$ 0.17	-0.8%
Non-Capacity - Energy - Secondary	$ 0.04345	$ 0.04901	12.8%	$ 0.04864	11.9%
Non-Capacity - Energy - Primary	$ 0.04863	$ 0.05295	8.9%	$ 0.05493	13.0%
Non-Capacity - Energy - Primary Off-Peak Discount	$ (0.01000)	$ (0.01000)	0.0%	$ (0.01000)	0.0%
Non-Capacity -Voltage Level Discount - Subtransmission	$ (0.00113)	$ (0.00070)	-38.5%	$ (0.00073)	-35.4%
Non-Capacity -Voltage Level Discount - Transmission	$ (0.00191)	$ (0.00155)	-19.0%	$ (0.00163)	-14.9%
Distribution:					
Distribution Charge - Secondary	$ 9.67	$ 11.82	22.2%	$ 12.09	25.0%
Distribution Charge - Primary	$ 4.21	$ 5.23	24.2%	$ 5.23	24.2%
Distribution Charge - Subtransmission	$ 1.65	$ 2.26	36.9%	$ 2.26	36.9%
Distribution Charge - Transmission	$ 0.70	$ 0.97	39.0%	$ 0.97	39.0%
Distribution - Substation Credit - Demand	$ (0.30)	$ (0.30)	0.0%	$ (0.30)	0.0%
Distribution - Substation Credit - Energy	$ (0.00040)	$ (0.00040)	0.0%	$ (0.00040)	0.0%
Primary - Interruptible Supply Rider (R10)					
Distribution - Service Charge - PV:	$ 70.00	$ 70.00	0.0%	$ 70.00	0.0%
Distribution - Service Charge - SV:	$ 375.00	$ 375.00	0.0%	$ 375.00	0.0%
Distribution - Service Charge - TV:	$ 375.00	$ 375.00	0.0%	$ 375.00	0.0%
Power Supply:					
Non-Capacity - Administrative Charge	$ 0.01676	$ 0.00775	-53.7%	$ 0.01102	-34.2%
Non-Capacity - MISO Energy Charge	$ 0.02545	$ 0.02790	9.6%	$ 0.02790	9.6%
Non-Capacity - Net Trans MISO MKT	$ 0.00740	$ 0.00756	2.2%	$ 0.00756	2.2%
Distribution:					
Distribution Charge - Primary	$ 4.21	$ 5.23	24.2%	$ 5.23	24.2%
Distribution Charge - Subtransmission	$ 1.65	$ 2.26	36.9%	$ 2.26	36.9%
Distribution Charge - Transmission	$ 0.70	$ 0.97	39.0%	$ 0.97	39.0%
Distribution - Substation Credit - Demand	$ (0.30)	$ (0.30)	0.0%	$ (0.30)	0.0%
Distribution - Substation Credit - Energy	$ (0.00040)	$ (0.00040)	0.0%	$ (0.00040)	0.0%

MPSC Case No.:	U-20561
Requestor:	Attorney General
Question No.:	AGDE-2.50]
Respondent:	P. W. Dennis
Page:	1 of 1

Question: Provide all analyses prepared by or for the Company that compares its present or proposed rates to other electric distribution companies. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Answer: The Company prepares a benchmarking study each spring and fall which compares DTE Electric rates and bills to other states using data obtained by U.S. Energy Information Administration. Attached is the spring 2019 study along with supporting documentation.

Attachments: U-20561 AGDE-2.50 Spring 2019 Benchmarking Study
U-20561 AGDE-2.50 Spring 2019 Benchmarking Study Support

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-1.13
Respondent:	A. Willis
	1 of 1

Question: Provide all analyses prepared by or for the Company that compare its present or proposed rates to other electric distribution companies. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Answer: See attachments.

Attachment: U-20836 AGDE-1.13 Spring 2021 Rate Benchmarking
U-20836 AGDE-1.13 Spring 2021 EIA Benchmarking Data