STATE OF MICHIGAN
DEPARTMENT OF ATTORNEY GENERAL

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DANA NESSEL
ATTORNEY GENERAL

November 6, 2019

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

Dear Ms. Felice:

Re: **MPSC Case No. U-20561**

Enclosed please find the ***Attorney General's Direct Testimony & Exhibits of Sebastian Coppola,*** and related Proof of Service.

Sincerely,

Joel King Digitally signed by Joel King
Date: 2019.11.06 18:00:34 -05'00'

Joel B. King
Assistant Attorney General

cc: All Parties

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-20561

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

November 6, 2019

TABLE OF CONTENTS

I. Introduction

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

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

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than thirty 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 analysis of power costs and filed testimony in power supply cost recovery mechanisms, including reconciliation of annual power supply costs.

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

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

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

- Filed testimony on behalf of the Michigan Attorney General in 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 Energy Gas Company (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 Consumers Energy Company (CECo) 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (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 Michigan Indiana Power Company (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 Company (DTE Gas) Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (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 DTE Electric 2018 electric rate Case U-20162 on several issues, including O&M expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Electric Division in case U-20286.

- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Gas Division in case U-20287.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (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 DTE Electric Company (DTEE) 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.

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-20561. 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
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 and Working Capital
6. The Fixed Bill Pilot
7. The AMI Program cost/benefit analysis
8. The Company's Time of Use (TOU) Rates Proposal

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 priority 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 Distribution Capital Expenditures Adjustments-Emergent Programs
4. Exhibit AG-1.4 Distribution Cap. Ex. Adjustments-New Connect, Business, Reloc,
5. Exhibit AG-1.5 Distribution Cap. Exp.- Gordie Howe Bridge Facilities Reloc.
6. Exhibit AG-1.6 Distribution Cap Ex. Adjustments to Strategic Capital Programs
7. Exhibit AG-1.7 Distribution Strategic Capital Programs Discovery Responses
8. Exhibit AG-1.8 Power Generation Large Routine Projects 2019
9. Exhibit AG-1.9 Power Generation Large Routine Projects 2020
10. Exhibit AG-1.10 Power Generation Large Routine Projects 2021
11. Exhibit AG-1.11 Capital Expenditures, Rate Base and Depreciation Adjustments
12. Exhibit AG-1.12 Power Generation Routine and Non-Routine Cap. Ex. Adjustments
13. Exhibit AG-1.13 IT Large Capital Projects
14. Exhibit AG-1.14 IT Capital Expenditures Adjustments
15. Exhibit AG-1.15 Working Capital Adjustments
16. Exhibit AG-1.16 Overall Cost of Capital
17. Exhibit AG-1.17 Cost of Common Equity-Summary
18. Exhibit AG-1.18 Cost of Common Equity-DCF
19. Exhibit AG-1.19 Cost of Common Equity-CAPM
20. Exhibit AG-1.20 Cost of Common Equity-Risk Premium
21. Exhibit AG-1.21 Electric ROE Decisions by Regulatory Commissions
22. Exhibit AG-1.22 Peer Group Analysis
23. Exhibit AG-1.23 Market to Book Ratios
24. Exhibit AG-1.24 Value Line Analysis of Water Companies
25. Exhibit AG-1.25 Historical Sales Analysis and Growth Rates
26. Exhibit AG-1.26 DTEE Discovery Responses – EWR and Distributed Generation
27. Exhibit AG-1.27 Residential Sales Revenue Adjustment
28. Exhibit AG-1.28 Commercial Sales Revenue Adjustment
29. Exhibit AG-1.29 Revised Billing Determinants
30. Exhibit AG-1.30 Updated Inflation Factors 2019 - 2021

31. Exhibit AG-1.31 DTEE Response – Distribution 2019 O&M Expense
32. Exhibit AG-1.32 Restoration O&M Expense Adjustments
33. Exhibit AG-1.33 Analysis of Steam, Hydraulic and Other Power O&M Expense
34. Exhibit AG-1.34 Power Generation 2019 O&M Expense Analysis
35. Exhibit AG-1.35 DTEE Response – St. Clair Unit #1 Retirement O&M Expense
36. Exhibit AG-1.36 St. Clair O&M Expense Reduction Adjustment
37. Exhibit AG-1.37 DTEE Response – Credit Card Study Information
38. Exhibit AG-1.38 Uncollectible Accounts Expense Adjustment
39. Exhibit AG-1.39 Incentive Compensation – Performance Measures Analysis
40. Exhibit AG-1.40 Incentive Compensation Capitalized
41. Exhibit AG-1.41 AG O&M Adjustment Summary
42. Exhibit AG-1.42 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 $350.7 million. This rate increase represents an overall increase in rates of 7.1% with a 9.1% increase to residential customers. As a result of the rate case adjustments I propose in my testimony, the average residential customer should see an increase of less than 1% in their total bill.

It is noteworthy to point out that during the five-year period from 2014 to 2018, the Company earned a return on common equity on a regulatory basis generally at or above the authorized ROE rate. In 2018, DTEE had an earned ROE of 10.1%.[1] That actual

[1] Exhibit A-2, Schedule A2, page 4.

earned ROE is considerably higher than the Company's true cost of capital, which is significantly less than 9%.[2]

Based on the foregoing analysis, I have identified several cost disallowances to the Company's proposed cost levels and capital projects, which I recommend that the Commission approve. As a result of these adjustments, I have determined that the Company has a revenue deficiency of $41.1 million. This result should not be surprising given the fact that the Company earned a ROE of 10.1% in 2018, and I now propose that the ROE in this rate case be set at 9.25%.

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

1. I propose higher residential and commercial sales for $12.2 million of additional revenue.
2. I propose a lower level of Operations and Maintenance expenses of $128.8 million for the test year.
3. I propose a reduction in capital expenditures of $455.1 million and a reduction in rate base of $420.8 million, including adjustments to working capital.
4. I propose a reduction in depreciation expense of $17.0 million pertaining to the proposed reductions in capital expenditures.
5. I recommend an authorized rate of return on equity of 9.25% which in comparison to the Company's proposed ROE rate of 10.50%, and higher

[2] Exhibit AG-1.17

short-term debt, results in a reduction in the revenue deficiency of $124.1 million.

6. I recommend that the Commission reject funding the Company's proposed fixed-bill pilot program.

7. I recommend that the Commission order the Company to establish a deferred regulatory account to record the actual excess deferred taxes amortized to expense annually versus the amount estimated in rates, with the balance of the account to be reflected in future rates. Furthermore, the Commission should direct the Company to file a letter under this case docket reporting the annual activity in the regulatory account.

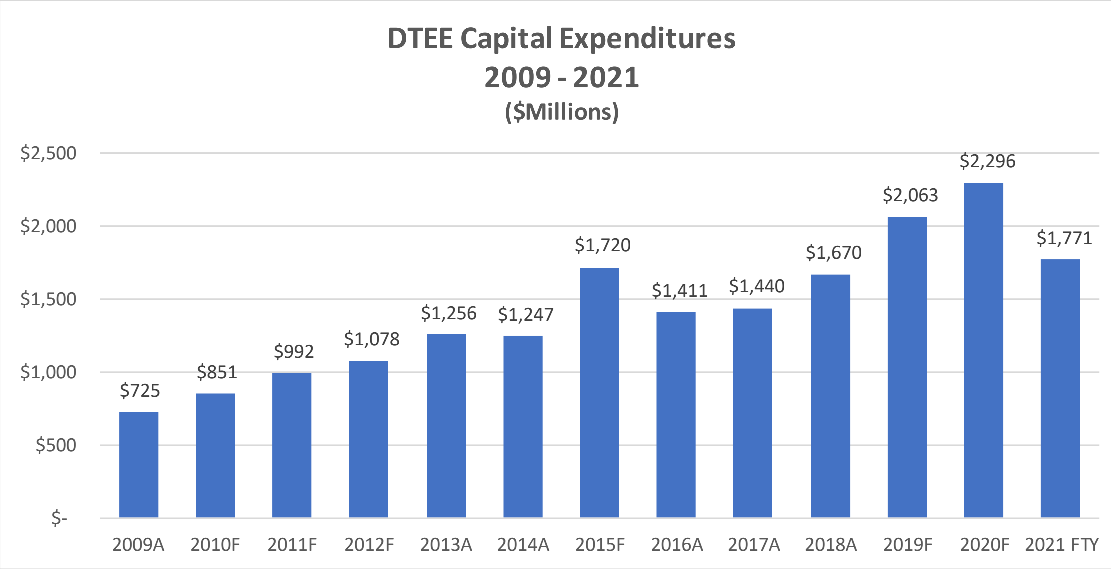
The remainder of my testimony provides further details and support for these summary conclusions and recommendations.

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 $2.1 billion for 2019, $765.4 million of the 4 months ending April 2020 ($2.3 billion annualized), and an additional $1.8 billion for the 12 months ending April 2021. The total proposed capital expenditures over this 28-month period are nearly $4.6 billion. These expenditures follow capital expenditures of $3.1 billion made during the prior two years in 2017 and 2018.[3] The following chart in Table 1 shows the dramatic increase in capital expenditures over recent years, in comparison to more moderate amounts in prior years.

Table 1



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 12%, to $18.3 billion. The proposed level of rate base in this rate case is more than double the amount of rate base the Company had 12 years ago.

[3] Exhibit A-12, Schedule B5 in Case No. U-20162 and Case No. U-20561.

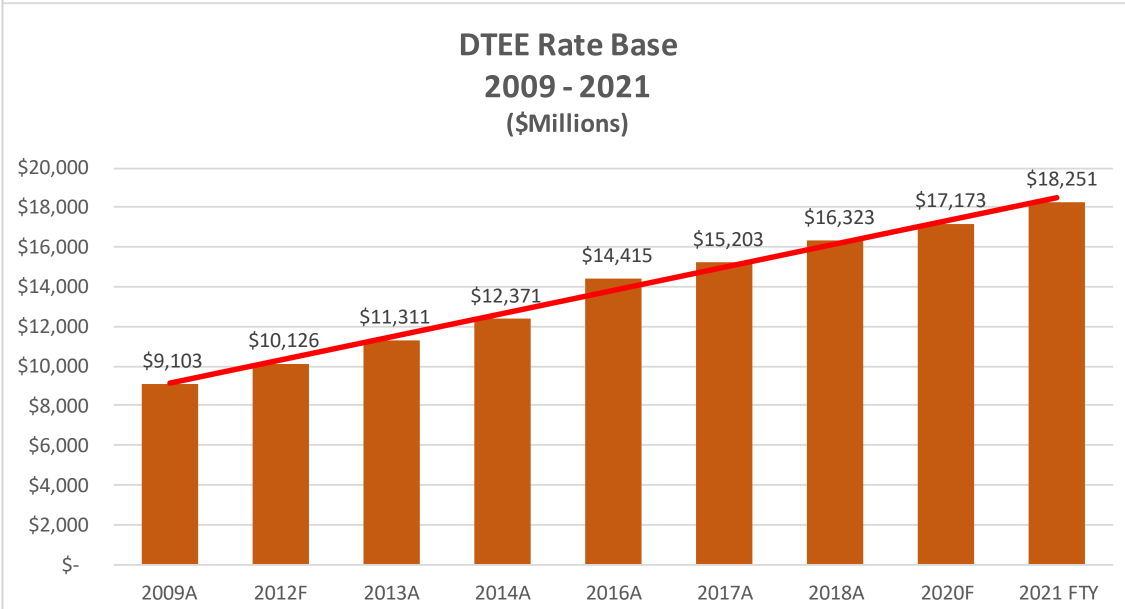
Table 2
DTE Electric Rate Base Growth
2009 to Projected 2021 Test Year

Rate Base Year	2009A	2012F	2013A	2014A	2016A	2017A	2018A	2021 FTY
Docket No.	U-16472	U-16472	U-17767	U-18014	U-18255	U-20162	U-20561	U-20162
Rate Base [1] (Millions)	$ 9,103	$ 10,126	$ 11,311	$ 12,371	$ 14,415	$ 15,203	$ 16,323	$ 18,251
Year over Year Change		11%	12%	9%	17%	5%	7%	12%
Cumulative Change over 2009 Rate Base		11%	24%	36%	58%	67%	79%	100%

[1] Historical actual rate base in each docket, except 2012, 2020 and 2021 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, 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.

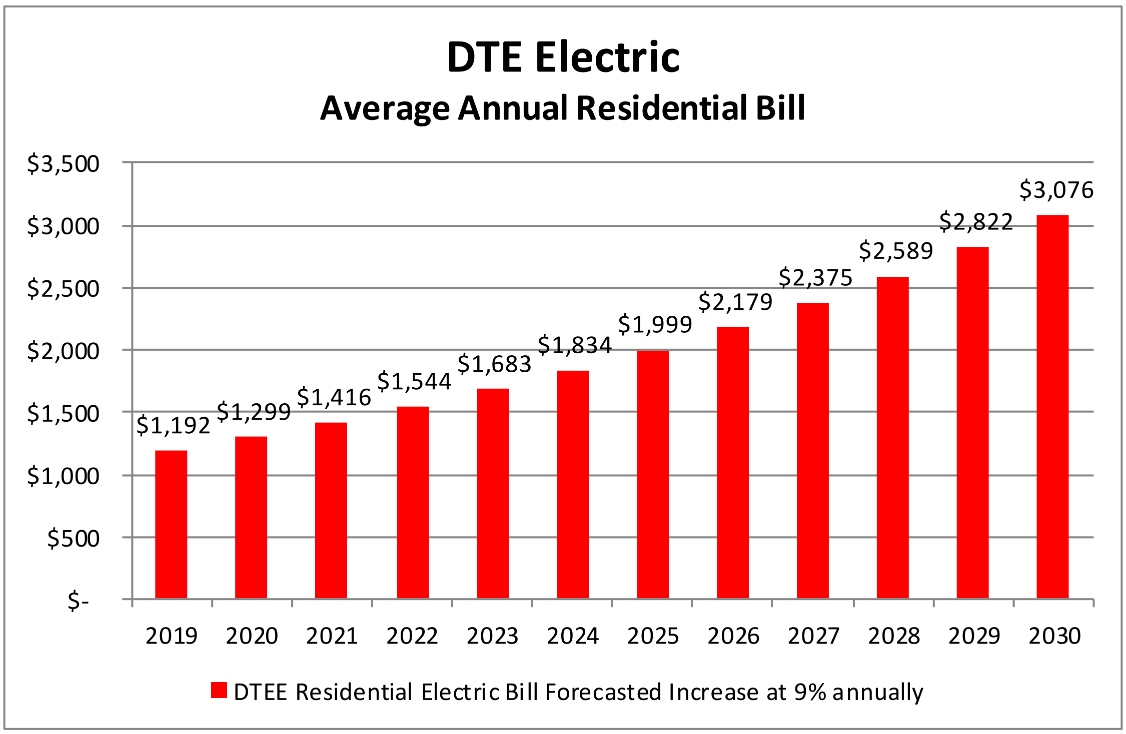
Second and perhaps a bigger driver, the replacement of aging electrical infrastructure has given the Company an opportunity to accelerate rate base growth in order to increase earnings growth. For utility companies, earnings growth is directly related to rate base growth. As shown in the tables above, 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 7% to 8%. Exhibit AG-1.1 includes pertinent pages from an October 2, 2019 Investor Presentation, which show this drive to increase earnings through increased capital spending at the utility. They also show 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 9%. 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 10 years will nearly triple from $1,192 in 2019 to $3,076 in 2030.[4] 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

[4] Current average electric bill in 2019 of $1,192 = Total Rate D1 revenue of $2,287,598,000 divided by 1,918,465 D1 residential customers per Exhibit A-16, Schedule F2, page 2 and F3, page 2. Current bill escalated at 9% per year through 2030.

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.

A. Contingent Capital Expenditures

The Company has disclosed that it has included total contingency costs of $17,745,000 in its forecasted capital expenditures for 2019 and the 16 months ending April 2021. This amount includes $14.6 million of contingency costs related to the Combined Cycle Plant being built by the Company for which it received separate approval in Case No. U-18419. Also included in the $17.7 million is $3.2 million for the Company's Headquarters Energy Center. Exhibit AG-1.2 includes the detailed schedules supporting these amounts as provided by the Company in response to discovery.

In the Company's prior rate case, Case No. U-20162, 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 order in Case Nos. 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 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 $17,745,000 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 $2.0 billion in capital expenditures for the 28 months ending April 2021 for additions to

Distribution Plant. After reviewing the testimony of Company witness Marco Bruzzano, related exhibits, and responses to discovery, I have identified capital expenditure reductions applicable to several areas.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES 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 2018 for these three programs was $345.9 million. The Company has forecasted $245.7 million for 2019, $82.6 million for the four months ending April 2020, and $247.4 million for the 12 months ending April 2021. According to Mr. Bruzzano's direct testimony, the Company decided to determine the forecasted amounts by using a five-year historical period of expenditures from 2014 to 2018 in order to normalize the expenditure level, and use as a base to apply projected annual inflation adjustments.[5]

Although the Company used the same approach in forecasting capital expenditures for each of the programs under the Emergent Program, I will address each of the three programs separately in proposing capital expenditure adjustments. Underlying my proposed adjustments in this area is the basic premise that the Company has not provided any evidence to show it has faced inflationary cost increases in prior years or that it will

[5] Mark Bruzzano direct testimony at page 99 and Exhibit A-12, Schedule B5.4, page 3.

face inflation cost increases in future years to the levels forecasted. Additionally, the Company calculations to arrive at its forecasted capital expenditures attempt to retroactively capture inflation cost increases by applying inflation adjustments to prior-year amounts from 2014 to 2018 in order to arrive at an average base amount for the five-year period. Such retroactive recovery of costs should not be permitted.

Page 3 of Exhibit A-12, Schedule B5.4, shows the calculations performed by the Company to arrive at the forecasted capital expenditures for each of the Emergent Replacement Programs. As shown in the exhibit, the Company has applied an inflation cost increase to each of the actual capital expenditures amounts from 2014 to 2018, and then applied additional inflation cost adjustments for each of the forecasted periods to arrive at its proposed capital expenditure amounts. Although I agree with the five-year normalization approach to forecast capital expenditures for future years, it should be done using actual capital expenditures from prior years, not by recasting numbers with additional assumed costs for prior year inflation. If any inflation was experienced in those prior years, it is reflected in the actual amounts. It is simply an unsupported fabrication to inflate historical costs to arrive at an adjusted historical base and to then further inflate those costs for future years with projected inflation factors.

As to the future inflation rates, the Company has assumed a rate of inflation of 2.8% for 2019 and 2.9% for 2020 and 2021, prorated for the applicable stub periods. The source for these rates is Exhibit A-13, Schedule C5.15. The Company has arrived at these rates by using blended rates of internally estimated wage inflation of 3% and the CPI-Urban index forecasted inflation rate of approximately 2%.[6] In prior rate cases, the Commission has disallowed the use of this blended approach and approved the use of the CPI-Urban index. Although, I understand the Commission decision to allow some adjustment for future inflation impact on costs, the responsibility should still be on the Company to demonstrate that in fact it has experienced inflationary cost increases, and will likely experience inflation cost increases in the future. However, there has been no such evidence presented by the Company in this case or prior rate cases. To the contrary, the Company boasts about having achieved actual operation and maintenance cost levels that are $222 million below the inflation adjusted amounts from 2009 to 2018.[7] This is clear and convincing evidence that the Company has not experienced inflationary cost increases in the past and is not likely to experience them for 2019 and through the end of the projected test year.

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

A. With regard to Storm-related capital expenditures, I propose that the Commission approve the actual five-year average amount of $101,136,000 for the 2014-2018 period, as shown on line 3, column (g) of Exhibit A-12, Schedule B5.4, page 3. This amount should be used for 2019, the four months ending April 2020 prorated at $33,379,000, and for the 12

[6] Exhibit A-13, Schedule C5.15.
[7] Michael Cooper's revised direct testimony at page 52.

months ending April 2021. When compared to the amounts proposed by the Company, it results in a reduction in capital expenditures of $6,120,000 for 2019, $3,067,000 for the 4 months ending April 2020, and $10,258,000 for the 12 months ending April 2021. The total amount of these three adjustments for the 28 months ending April 2021 is $19,445,000. Exhibit AG-1.3 shows the calculations to arrive at these amounts.

Should the Commission decide to allow some inflationary cost increases for future periods, I recommend using a 2% inflation rate, equivalent to the CPI-Urban index, beginning in 2020. The year 2019 is nearly over and new rates will not go into effect until the beginning of the projected test year, which starts in May 2020. Using this approach, the disallowance for 2019 remains at $6,120,000, and the disallowances for the four months ending April 2020 and 12 months ending April 2021 decline to $2,844,000 and $7,574,000, respectively. Under this approach, the total disallowance for Storm-related capital expenditures is $16,358,000. Exhibit AG-1.3 also shows these calculations.

For Non-Storm capital expenditures, I propose that the Commission approve the actual five-year average amount of $101,141,000 for the 2014-2018 period, as shown on line 10, column (g) of Exhibit A-12, Schedule B5.4, page 3. This amount should be used for 2019, the four months ending April 2020 prorated at $33,714,000, and for the 12 months ending April 2021. When compared to the amounts proposed by the Company, it results in a reduction in capital expenditures of $5,915,000 for 2019, $3,006,000 for the 4 months ending April 2020, and $10,084,000 for the 12 months ending April 2021. The total amount of these three adjustments for the 28 months ending April 2021 is $19,005,000. Exhibit AG-1.3 shows the calculations to arrive at these amounts.

If the Commission decides to approve some inflation adjustment for future Non-Storm expenditures, I recommend using a 2% inflation rate, equivalent to the CPI-Urban index, beginning in 2020. Therefore, the disallowance for 2019 remains at $5,915,000, and the disallowances for the four months ending April 2020 and 12 months ending April 2021 decline to $2,781,000 and $7,373,000, respectively. Under this approach, the total disallowance for Non-Storm capital expenditures is $16,069,000. Exhibit AG-1.3 also shows these calculations.

With regard to capital expenditures for the Substation Reactive Program, I propose that the Commission approve the actual five-year average amount of $31,657,000 for the 2014-2018 period, as shown on line 17, column (g) of Exhibit A-12, Schedule B5.4, page 3. This amount should be used for 2019, the four months ending April 2020 prorated at $10,552,000, and for the 12 months ending April 2021. When compared to the amounts proposed by the Company, it results in a reduction in capital expenditures of $1,922,000 for 2019, $966,000 for the 4 months ending April 2020, and $3,230,000 for the 12 months ending April 2021. The total amount of these three adjustments for the 28 months ending April 2021 is $6,118,000. Exhibit AG-1.3 shows the calculations used to arrive at these amounts.

If the Commission decides to approve some inflation adjustment for future Substation Reactive expenditures, I recommend using a 2% inflation rate, equivalent to the CPI-Urban index, beginning in 2020. Therefore, the disallowance for 2019 remains at $1,922,000, and the disallowances for the four months ending April 2020 and 12 months ending April 2021 decline to $896,000 and $2,382,000, respectively. Under this approach, the total disallowance for Substation Reactive capital expenditures is $5,200,000. Exhibit AG-1.3 also shows these calculations.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF CAPITAL EXPENDITURES FOR NEW CUSTOMER CONNECTIONS AND NEW BUSINESS PROGRAMS.

A. On page 4 of Exhibit A-12, B5.4, the Company shows the two major capital programs for New Customer Connections and New Business Projects. The Company has taken a similar approach in forecasting future capital expenditures for these programs as it did for the Emergent Replacement Programs discussed above, by adding an inflation factor to the historical capital expenditures. However, instead of using an average five-year historical period as a base, it used the 2018 actual expenditures as its starting point. Although the 2018 capital spending level of New Connections represents the highest amount spent in the past five years by a wide margin, I understand that because of the expanding Michigan economy and the construction activity within the city of Detroit, demand for new customer connections has increased annually. Similarly, for new Business Projects, the 2018 capital spending amount is above the 5-year average but in line with the average amount for the most recent three years. Therefore, I find the 2018 capital spending levels to be reasonable, albeit somewhat high.

As stated earlier, there is no basis for the Company to apply an inflation factor to the 2018 capital spending level to project capital spending over approximately the next two years. Therefore, I recommend that the Commission approve the same amount of capital expenditures incurred in 2018 for future periods, prorated accordingly for stub periods. As such, I propose that the Commission approve the actual amount of $108,257,000 spent in 2018 for future periods for the combined New Customer Connections and New Business Projects, as shown on line 11, column (b) of Exhibit A-12, Schedule B5.4, page 4. This amount should be used for 2019, the four months ending April 2020 prorated at $36,086,000, and for the 12 months ending April 2021. When compared to the amounts proposed by the Company, it results in a reduction in capital expenditures of $3,031,000 for 2019, $2,086,000 for the 4 months ending April 2020, and $7,365,000 for the 12 months ending April 2021. The total amount of these three adjustments for the 28 months ending April 2021 is $12,482,000. Exhibit AG-1.4 shows the calculations to arrive at these amounts.

If the Commission decides to approve some inflation adjustment for future capital expenditures for these programs, I recommend using a 2% inflation rate, equivalent to the CPI-Urban index, beginning in 2020. Therefore, the disallowance for 2019 remains at $3,031,000, and the disallowances for the four months ending April 2020 and 12 months ending April 2021 decline to $1,845,000 and $4,464,000, respectively. Under this approach, the total disallowance for projected capital expenditures for New Customer Connections and New Business Programs is $9,340,000. Exhibit AG-1.4 also shows these calculations.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF CAPITAL EXPENDITURES FOR FACILITY RELOCATION PROJECTS.

A. On page 4 of Exhibit A-12, B5.4, the Company has subdivided the capital expenditures for Relocation Projects between the larger project of relocating electrical facilities near the Gordie Howe International Bridge (GHIB)and the smaller routine relocation projects. Although, the company has calculated the forecasted capital expenditures for routine relocation projects by applying an inflation factor to the 2018 base amount, the adjustments are relatively small and I do not propose any adjustments.

However, with regard to the projected capital expenditures for the GHIB project, I recommend that the amount of $8,950,000 to be spent in 2019 and 2020 be disallowed. This amount represents half of the incremental cost of relocating the Company electrical distribution facilities at the bridge plaza or surrounding area. On page 4, line 15, of Exhibit A-12, Schedule B5.4, the Company shows the gross amount of capital expenditures of $12.3 million in 2019 and $5.6 million in 2020. However, according to the Company half of this incremental cost will be paid by the GHIB Authority and those payments supposedly are reflected in the Contributions in Aid of Construction (CIAC) on line 17 and 20 of the exhibit.

In discovery, the Company was asked to explain why this project will require an additional $18.9 million in capital expenditures, on top of the $10.9 million spent in 2018. In several responses, the Company stated that the scope of the project changed, requiring a budget increase of $18.5 million, of which the Company will be responsible for half.[8] The Company also stated that it originally proposed vacating its facilities from the Port of Entry (POE), but the Windsor Detroit Bridge Authority (WDBA) deemed the plans to be cost prohibitive. Therefore, the Company and the WDBA apparently proceeded with an alternative plan. However, now the parties are finding that soil conditions prevent the location of the DTEE facilities at the originally planned site and relocation to a different site is necessary. Exhibit AG-1.5 includes the Company's discovery responses.

This relocation raises questions about the competency of the original work done and the decision to choose the original location. In addition, this is work specifically required to benefit the WDBA at an extraordinarily high cost, which is now nearly $29 million. The other customers of the Company do not benefit from these capital expenditures. Therefore, any additional costs to relocate the facilities should not be paid by the rest of DTEE's customers by including them in rate base. The entire incremental costs to complete the relocation should be paid by the WDBA. If the Company agreed to pay for half of the

[8] The amounts provided in discovery responses are slightly different than the amounts shown in Exhibit A-12, Schedule B5.4, likely due to the timing of when the original and incremental expenditures will be incurred.

incremental costs, then it should absorb those costs and not burden its customers with higher costs.

Therefore, I recommend that the Commission remove $6,150,000 of capital expenditures from 2019, $934,000 for the four months ending April 2020, and $1,867,000 for the 12 months ending April 2021. This is a total disallowance of $8,950,000 for the 28 month period and assumes that the Company has included half of the costs for the incremental project costs in the CIAC amounts in Exhibit A-12, Schedule B5.4, page 4, line 17 or 20. If the Company has not included the appropriate amount of CIAC, then a higher amount up to the total amount shown on line 15 of the exhibit for 2019 and 2020 should be disallowed.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF CAPITAL EXPENDITURES FOR ELECTRIC SYSTEM EQUIPMENT.

A. On page 4 of Exhibit A-12, B5.4, the Company has identified the three capital programs under Electric System Equipment. The 2018 capital spending in these programs is in line with recent prior years. Therefore, I find the 2018 capital spending levels to be reasonable.

However, as stated earlier, there is no basis for the Company to apply an inflation factor to the 2018 capital spending level to project capital spending over approximately the next two years. Therefore, I recommend that the Commission approve the same amount of capital expenditures incurred in 2018 to future periods and appropriately prorated for stub periods. As such, I propose that the Commission approve the actual amount of

$51,967,000 spent in 2018 for the three combined programs, as shown on line 26, column (b) of Exhibit A-12, Schedule B5.4, page 4. This amount should be used for 2019, the four months ending April 2020 prorated at $17,322,000, and for the 12 months ending April 2021. When compared to the amounts proposed by the Company, it results in a reduction in capital expenditures of $1,455,000 for 2019, $1,002,000 for the 4 months ending April 2020, and $3,535,000 for the 12 months ending April 2021. The total amount of these three adjustments for the 28 months ending April 2021 is $5,992,000. Exhibit AG-1.4 shows the calculations used to arrive at these amounts.

If the Commission decides to approve some inflation adjustment for future capital expenditures for these programs, I recommend using a 2% inflation rate, equivalent to the CPI-Urban index, beginning in 2020. Therefore. the disallowance for 2019 remains at $1,455,000, and the disallowances for the four months ending April 2020 and 12 months ending April 2021 decline to $887,000 and $2,142,000, respectively. Under this approach, the total disallowance for projected capital expenditures for Electric System Equipment is $2,142,000. Exhibit AG-1.4 also shows these calculations.

Q. ARE YOU PROPOSING ANY DISALLOWANCES TO THE CAPITAL EXPENDITURES PROJECTED BY THE COMPANY FOR NRUC AND IMPROVEMENT BLANKETS?

A. No. The proposed capital expenditures in this area are relatively small and I do not see a need to propose any adjustments.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF CAPITAL EXPENDITURES FOR STRATEGIC CAPITAL PROGRAMS.

A. On page 1 of Exhibit A-12, B5.4, the Company has identified the three major capital programs under Strategic Capital Programs. The total amount of capital expenditures for the three programs was $280.0 million in 2018, and is forecasted at $391.7 million for 2019, $126.5 million for the four months ending April 2020, and $393.6 million for the 12 months ending April 2021. The total amount of proposed spending in these three programs over the forecasted 28 months is $912.0 million.

On page 16 of his direct testimony, Mr. Bruzzano has included Table 6, which compares 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 his testimony, Mr. Bruzzano explains 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 two major storms in 2018.

In discovery, the Company was asked to explain its commitment going forward to spend funding for these programs if approved by the Commission. In two responses, the Company provided somewhat contradictory answers. In discovery request AGDE-3.72a the Company was asked the following question and provided the answer shown below:

> **Question:** Refer to page 16, lines 10-12, of Mr. Bruzzano's direct testimony. Please explain how the Company can make any progress in achieving infrastructure Resilience, Hardening and Redesign if it pulls capital spending away from these programs when other issues arise whether emergent or otherwise.
>
> **Answer:** It is the Company's goal to invest in Infrastructure Resilience & Hardening and Infrastructure Redesign as described in my testimony because these investments will benefit customers… The Company plans to make the investments forecasted in this case unless unforeseen events, such as the severe weather that led to high levels of emergent replacements in 2018, require resources to be diverted on a temporary basis. The Company expects to continue making progress in its strategic investments and has already done so.

In response to discovery request AGDE-3.85, the Company provided a more affirmative answer but still highly hedged, after the customary legal objection, to a question pertaining to potential negative consequence on the electrical system if the Company did not receive the proposed funding for the three programs:

> **Question:** Refer to page 38, lines 12-25, and page 39, line 1-2, of Mr. Bruzzano's direct testimony. Please explain if the same negative consequences occurred as a result of the Company reducing the Strategic Capital Investments in 2018 from the levels approved and funded by the Commission in Case No. U-20162.
>
> **Answer:** DTE Electric objects for the reason that the request is argumentative since the Commission approves rates and not funding levels for specific categories. In further answer, without waiving the objection, the answer is yes. For this reason, the Company plans to execute its full slate of strategic investments, even if unforeseen factors in any given year (such as large storms) cause these investments to be delayed.

The full text of these and other discovery responses on this matter are included in Exhibit AG-1.7.

To establish whether 2018 was an anomaly, I reviewed the capital spending for these programs for the 9 months ended September 2019 against the forecasted expenditures for the same period. The result of that analysis is that the Company has again significantly underspent its forecasted capital expenditures during the first nine month of 2019 by approximately 21%, and in some categories, such as Technology and Automation, by as much as 32%. Exhibit AG-1.6 shows this comparison based on actual and forecasted capital expenditure information provided by the Company.

The conclusion I reach from reviewing Mr. Bruzzano's testimony, the discovery responses, and the 2019 year-to-date capital spending is that the Company is not likely to reach the spending levels for the Strategic Capital Programs proposed in Exhibit A-12, Schedule B5.4, page 1. The commitment to spend the requested amounts is consistently reneged upon, once other programs require more funding. Weather events occur, to some degree or another, every year and will continue to do so in the future. If the Company's commitment to spend on these programs is so highly dependent on weather events, then it is not a commitment at all.

Therefore, as a reasonable adjustment, I propose that the Commission remove 20% of the proposed capital spending for 2019 and future periods. The 20% is in line with the overall underspending percentage for Strategic Capital Programs occurring during the first 9 months of 2019, and is still significantly below the 31% that occurred in 2018. As a result of this adjustment, I recommend that the Commission remove $78,313,000 from 2019 capital expenditures, $25,301,000 for the 4 months ending April 2020 and $78,727,000 for the 12 months ending April 2021. The total amount of adjustments for the 28 months period is $182,341,000. The calculations supporting these adjustments are shown in Exhibit AG-1.6.

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 of $697.3 million for 2019, $295.4 million for the four months ending April 2020, and $519.8 million for the 12 months ending April 2021 for Power Generation Routine capital projects. In my review of the proposed expenditures, I have identified total adjustments of $43.0 million in Routine projects and $40.8 million in Non-Routine projects.

Q. PLEASE DISCUSS THE ADJUSTMENTS YOU PROPOSE TO ROUTINE POWER GENERATION PROJECTS FOR 2019.

A. In discovery the Company was asked to provide detailed information on projects with capital expenditures of $3 million or greater.

For 2019, the Company provided project level information on 17 projects, including the project capital funding and approval documents, which the Company refers as a "PAT Review Request Form." After reviewing each of the projects and related documents, I have determined that reductions to the capital expenditure amounts for five of the projects for 2019 are necessary. I will discuss each of them separately.

__Belle River Unit #1 Turbine Steam Path Replacement__ - The first project is the Belle River Unit #1 Turbine Steam Path Replacement, which is PMP Project 13739. According to a February 27, 2018 version of the PAT form, this project was to start in March 2021 and be installed in May 2021, with only initial funding of $100,000 approved on February 27, 2018. A subsequent PAT form, dated February 20, 2019, changed the start date to February 6, 2019 and an installation date of June 10, 2019. However, in the project summary, the Company states that this project approval authorizes the purchases of a new HP Turbine rotor and inner casing for installation of the equipment during the Unit #1 Spring 2021 periodic outage. The February 2019 PAT form shows $3.3 million of funding for the project to be spent in 2018 and $8.5 million in 2019, before a contingency amount. However, after reviewing the detailed actual capital spending report for 2018 provided by the Company, it appears that no capital expenditures were incurred for this project in 2018. Given the lack of spending in 2018 and the uncertain dates when this project will begin and end, it is my conclusion that the requested capital spending on this project will not likely occur within the projected periods. Therefore, I recommend that the entire amount of $7,212,002 forecasted by the Company for 2019 be removed. Exhibit AG-1.8 includes the information provided by the Company about this project.

__Monroe Power Plant Unit #3 SCR Catalyst Layers replacement__ - The second project is the Monroe Power Plant Unit #3 SCR Catalyst Layers replacement, PMP Project 13725. The capital expenditures amount included in the Company's forecast for 2019 is $6,819,992. The approved amount on the project PAT form dated May 8, 2019 is

$6,473,121, excluding the contingency amount. The difference is $346,871. The rate case forecast is not supported by the project approval document. Therefore, I recommend that the $346,871 be removed for the rate case forecast for 2019. Exhibit AG-1.8 includes the project approved PAT form.

<u>*Monroe Unit #3 Expansion Joint Replacement*</u> - The third project is the Monroe Unit #3 Expansion Joint Replacement, PMP Project 13599. The capital expenditures amount included in the Company's forecast for 2019 is $5,100,423. The approved amount on the project PAT form dated May 8, 2019 is $4,040,223, excluding the contingency amount (Calculated Risk). The difference is $1,060,200. The rate case forecast is not supported by the project approval document. Therefore, I recommend that the $1,060,200 be removed for the rate case forecast for 2019. Exhibit AG-1.8 includes the project approved PAT form.

<u>*Belle River Unit 13-1 Major Overhaul*</u> - The fourth project is the Belle River Unit 13-1 Major Overhaul, PMP Project 14426. The capital expenditures amount included in the Company's forecast for 2019 is $7,500,000. The approved amount on the project PAT form dated March 27, 2019 is $6,921,097, excluding the contingency amount. The difference is $578,903. The rate case forecast is not supported by the project approval document. Therefore, I recommend that the $578,903 be removed for the rate case forecast for 2019. Exhibit AG-1.8 includes the project approved PAT form.

Delray Gas Compressors replacement - The fifth project is the Delray Gas Compressors replacement, PMP Project 10570. The capital expenditures amount included in the Company's forecast for 2019 is $4,000,000, which appears to be a "ballpark" amount. The project PAT form dated March 27, 2019 describes the project summary scope as follows: "Vendor to prepare a gas compressor technology assessment to assist DTE in selecting new compressors. Once compressors technology is chosen by DTE, vendor will provide a formal bid spec." This description indicates that the project is in the early stages of development with no decisions made as to how to proceed with the project. The forecast appears to be a "ballpark" amount as a placeholder for the purpose of preparing a rate case forecast. The project and cost estimate are premature for inclusion in this rate case. Therefore, I recommend that the entire $4 million be removed from the forecasted capital expenditures for 2019. Exhibit AG-1.8 includes the project approved PAT form.

In total, I recommend the removal of $13,198,000 of forecasted capital expenditures for 2019. Exhibit AG-1.12 provides a summary of the expenditures of each project supporting this disallowance amount.

Q. PLEASE DISCUSS THE ADJUSTMENTS YOU PROPOSE TO ROUTINE POWER GENERATION PROJECTS FOR 2020.

A. In response to discovery, the Company provided project level information on 18 projects with capital spending in 2020 of $3 million or greater, including the PAT Review Request Form described above. After reviewing each of the projects and related documents, I have determined that reductions to the capital expenditure amounts for 8 projects for 2020 are necessary. I will discuss each of them separately.

<u>Belle River Unit #2 LP Turbine Blade Replacement</u> - The first project is the Belle River Unit #2 LP Turbine Blade Replacement, PMP Project 13574. The capital expenditures amount included in the Company's forecast for 2020 is $7,448,100. The approved amount on the project PAT form dated January 1, 2019 is $6,200,707 for Future Years, excluding the contingency amount (Calculated Risk). The difference is $1,247,393. Although, it is not clear if Future Years is only 2020, or may include subsequent years, the rate case forecast is not supported by the project approval document. Therefore, I recommend that at least $1,247,393 be removed for the rate case forecast for 2020. A case could be made that the entire amount of $7,448,100 should be removed given that there is no specific approval for spending this amount on the project in 2020. Exhibit AG-1.9 includes the project approved PAT form.

<u>Belle River Unit #2 IP Turbine Blade Replacement</u> - The second project is the Belle River Unit #2 IP Turbine Blade Replacement, PMP Project 14941. The capital expenditures amount included in the Company's forecast for 2020 is $4,884,000. The approved amount on the project PAT form dated May 9, 2019 is $1,362,402 for 2020, excluding the contingency amount (Calculated Risk). The difference is $3,521,598. The rate case forecast is not supported by the project approval document. Therefore, I recommend that the $3,521,598 be removed for the rate case forecast for 2020. Exhibit AG-1.9 includes the project approved PAT form.

<u>Greenwood Unit #1 Main Unit Transformer Replacement</u> - The third project is the Greenwood Unit #1 Main Unit Transformer Replacement which is PMP Project 13378. The capital expenditures amount included in the Company's forecast for 2020 is $8,000,000. The approved amount on the project PAT form dated January 30, 2019 is $7,599,249 for 2020. The difference is $400,751. The rate case forecast is not supported by the project approval document. Therefore, I recommend that the $400,751 be removed for the rate case forecast for 2020. Exhibit AG-1.9 includes the project approved PAT form.

<u>Monroe Unit #4 Secondary Superheat Inlet Pendant Replacement</u> - The fourth project is the Monroe Unit #4 Secondary Superheat Inlet Pendant Replacement, PMP Project 9974. The capital expenditures amount included in the Company's forecast for 2020 is $12,281,614. The approved amount on the project PAT form dated March 25, 2019 is $11,696,085 for Future Years, excluding the contingency amount. The difference is $585,529. Although, it is not clear if Future Years is only 2020 or may include subsequent years, the rate case forecast amount is not supported by the project approval document. Therefore, I recommend that at least $585,529 be removed for the rate case forecast for 2020. A case could be made that the entire amount of $12,281,614 should be removed given that there is no specific approval for spending this amount on the project for 2020. Exhibit AG-1.9 includes the project approved PAT form.

<u>Monroe Unit #4 Generator Stator Rewind</u> - The fifth project is the Monroe Unit #4 Generator Stator Rewind, PMP Project 13982. The capital expenditures amount included

in the Company's forecast for 2020 is $8,400,000. The approved amount on the project PAT form dated December 21, 2018 is $8,111,337 for Future Years, excluding the contingency amount. The difference is $288,663. Although, it is not clear if Future Years is only 2020 or may include subsequent years, the rate case forecast is not supported by the project approval document. Therefore, I recommend that at least $288,663 be removed for the rate case forecast for 2020. A case could be made that the entire amount of $8,400,000 should be removed given that there is no specific approval for spending this amount on the project for 2020. Exhibit AG-1.9 includes the project approved PAT form.

Monroe Turbine & Boiler House Roof Vent Fan Replacement - The sixth project is the Monroe Turbine & Boiler House Roof Vent Fan Replacement, PMP Project 12227. The capital expenditures amount included in the Company's forecast for 2020 is $3,000,000, which appears to be a "ballpark" amount. The project PAT form dated December 5, 2018 describes the reason for project submittal as follows: "At this time, this project is below the line for 2019. It is understood that the funding approved with this request is limited to support the development of an equipment specification and the work to support the bid event for the new fans. Any further engineering or procurement is not allowed until a funding path is established for execution." This description indicates that the project is in the early stages of development with no decisions made as to how to proceed with the project. The forecast appears to be a "ballpark" amount as a placeholder for purpose of preparing a rate case forecast. The Commission has previously rejected such placeholder amounts. The project and cost estimate are premature for inclusion in this rate case.

Therefore, I recommend that the entire $3 million be removed from the forecast capital expenditures for 2020. Exhibit AG-1.9 includes the project approved PAT form.

Hancock 11-4 Peaker Hot Gas Path Overhaul - The seventh project is the Hancock 11-4 Peaker Hot Gas Path Overhaul, PMP Project 15046. The capital expenditures amount included in the Company's forecast for 2020 is $4,000,000. The project PAT form provided to support the capital expenditure is neither dated nor signed. The forecast appears to be a "ballpark" amount as a placeholder for purpose of preparing a rate case forecast. The Commission has previously rejected such placeholder amounts. The project and cost estimate are premature for inclusion in this rate case. Therefore, I recommend that the entire $4 million be removed from the forecast capital expenditures for 2020. Exhibit AG-1.9 includes the project PAT form provided.

Renaissance Unit #1 Peaker Turbine Combustion Cans and Hot Gas Path Replacement - The eighth project is the Renaissance Unit #1 Peaker Turbine Combustion Cans and Hot Gas Path Replacement, PMP Project 14422. The capital expenditures amount included in the Company's forecast for 2020 is $4,000,000. The project PAT form provided to support the capital expenditure is neither dated nor signed. The forecast appears to be a "ballpark" amount as a placeholder for purpose of preparing a rate case forecast. The Commission has previously rejected such placeholder amounts. The project and cost estimate are premature for inclusion in this rate case. Therefore, I recommend that the entire $4 million be removed from the forecast capital expenditures for 2020. Exhibit AG-1.9 includes the project PAT form provided.

In total, I recommend the removal of $17,044,000 of forecasted capital expenditures for 2020, with $5,681,000 pertaining to the four months ending April 2020 and $11,363,000 pertaining to the 12 months ending April 2021. Exhibit AG-1.12 provides a summary of the projects supporting this amount.

Q. PLEASE DISCUSS THE ADJUSTMENTS YOU PROPOSE TO ROUTINE POWER GENERATION PROJECTS FOR 2021.

A. On page 7 of Exhibit A-12, Schedule B5.1, the Company listed 7 projects with expenditures above $1 million during the four months ending April 2021. The Total amount of forecasted capital spending for these projects during the 4-month period is $12.8 million. After reviewing the project PAT Request forms for most of these projects, the projects do not have dated or approved PAT forms or have forms with no designated and approved capital spending for 2021.

The forecasted amounts appear to be "ballpark" amounts as a placeholder for purpose of preparing a rate case forecast. The Commission has previously rejected such placeholder amounts. The projects and cost estimates are premature for inclusion in this rate case. Therefore, I recommend that the entire $12.8 million be removed from the forecast capital expenditures for 2021. Exhibit AG-1.10 includes the projects' PAT forms provided by the Company.

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO NON-ROUTINE POWER GENERATION PROJECTS.

A. On line 13 of page 2 of Exhibit A-12, Schedule B5.1, the Company has identified capital expenditures for the Monroe Bottom Ash Basin Closure. The Company incurred $1.6 million of capital expenditures for this project in 2018, and has proposed capital spending of $11,652,000 for 2019, $8,219,000 for the four months ending April 2020, and $20,914,000 for the 12 months ending April 2021.

On page 28 of his testimony, Company witness Justin Morren briefly describes this project as the removal of all bottom ash from the inactive bottom ash basin at the Monroe Power Plant to meet the EPA's Coal Combustion Residual (CCR) requirements. He further states that the project includes engineering, road and bridge upgrades, and associated trucking to support transporting approximately 2 million cubic yards of bottom ash from the Monroe inactive bottom ash basin to the Sibley Quarry.

The CCR requirements emanate from the Resource Conservation Recovery Act (RCRA). However, with the enactment of the Water Infrastructure Improvements for the Nation (WIIN) Act of 2016, utilities can develop alternative CCR compliance programs working with state agencies. According to a discovery response from the Company on this matter, the Company stated that the Michigan Department of Environment, Great Lakes and Energy (EGLE) is working with Michigan utilities and other stakeholders to develop of a state program. Although there may be some similarities between the EPA compliance rules and the rules promulgated by EGLE, it is premature to spend over $40 million over the next two years and four months for a program that still may change and has no definitive rules set by the state agency.

Consumers Energy faces the same compliance requirements. In her testimony in Case No. U-20134, Consumers Energy witness Heather Breining elaborated on the compliance requirements and enforcement rules, as follows:

> The new [CCR] rules establish minimum national criteria for purposes of determining which CCR solid waste disposal facilities and solid waste management practices pose a reasonable probability of adverse effect on health or the environment under RCRA. The rule is considered self-implementing, meaning that affected facilities must certify compliance with the published standards and schedules despite existing state rules or adaptation of state rules to encompass new standards. By codifying standards under Subtitle D, Owners and Operators are not required to obtain permits, and states are not required to adopt and implement the new rules. Instead, the rules' only enforcement mechanism is for a state or citizen group to bring a RCRA citizen suit in federal district court against any facility that is alleged to be in noncompliance with the newly promulgated minimum standards. In December 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was passed. This bill provides authority for state implementation of coal ash management through a state permit program in lieu of the current enforcement of the CCR Rule through the RCRA Citizen Suit Authority. States may elect to submit a CCR 5 permit program to the EPA for approval, and the EPA must either approve the permit program or enforce its own. The State of Michigan is currently in discussions with Stakeholders on how best to implement a state program. In the interim the EPA has direct enforcement authority of the RCRA-CCR Rule in addition to states and citizens.
>
> With the passage of the WIIN Act in late December 2016, and subsequent discussions with the MDEQ on how best to implement a state program, there exists a high likelihood that the State of Michigan will apply to the EPA to have a permitting program for CCR by 2019 or later. The existence of a state permitting program would allow the DEQ [MDEGLE] to issue permits under the solid waste management law (Part 115 of the Natural Resources and Protection Act of 1994 ("NREPA"), as amended) and in surface impoundments (via Part 31 of NREPA) to regulate compliance schedules and activities for CCR landfills and surface impoundments in lieu of self-implementing compliance activities. State CCR permitting programs must be approved by the EPA on the basis that they are "as protective as" the CCR Rule. Thus, similar compliance standards will be required within the state permitting program…[9]

[9] MPSC Case No. U-20134, Heather Breining direct testimony on pages 7-10.

Until EGLE issues new compliance rules that have been approved by the EPA, it is premature to spend millions of dollars on this project. Therefore, I recommend that the Commission remove the projected capital expenditures of $40,785,000 for this project for 2019 and through the end of April 2021 from this rate case.

Q. WHAT IS THE TOTAL AMOUNT OF ADJUSTMENTS THAT YOU PROPOSE FOR GENERATION PLANT EXPENDITURES?

A. I recommend that the Commission remove total capital expenditures of $83.8 million pertaining to Power Generation capital projects. Exhibit AG-1.12 shows the determination of the specific disallowances by forecasted period for removal from projected rate base.

D. Information Technology Projects

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

A. On page 1 of Exhibit A-12, Schedule B5.7, the Company shows the historical and projected capital expenditures for Information Technology (IT) projects. During 2018, the Company spent $79.2 million on IT projects. However, for 2019 the Company has projected a major escalation in capital spending to $98.3 million, followed by $35.1 million in the four months ending April 2020 ($105.2 million annualized) and $136.7 million for the 12 months ending April 2021. At a time when the Company needs to spend more capital to improve aging electrical infrastructure, it is perplexing as to why the Company has undertaken more IT projects with an increase in capital spending of nearly $58 million between 2018 and the 12 months ending April 2021.

The Company has proposed over 100 IT projects to be undertaken, or that will be on-going over the 28-month forecasted period. After reviewing the top 25 IT projects, I have identified 7 projects that do not appear to qualify as priority projects and should be removed from the capital expenditures approved in this rate case. The total amount of projected capital spending for the 7 projects for the period from 2019 to the end of April 2021 is $54.8 million. The 7 projects are: Applied Innovation, Digital Innovation, Success Factors Program, Web Portal Rebuild, Bill Redesign, Pay to Purchase, and the Fixed Bill project. I will discuss each of the projects in my testimony below.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF THE CAPITAL EXPENDITURES FOR THE APPLIED INNOVATION IT PROJECT.

A. The Company describes the Applied Innovation project as a tool for "[the] Innovation Program Management Office to provide oversight and direction with director-level and president-level oversight to ensure that the more relevant innovation items are pursued." The projected cost over the two years 2020 and 2021 is $8.0 million. The project document filed by the Company as part of its Part III filing requirements identifies "the delivery of approved innovative business benefits in a rapid manner" as the only benefit of the project.

No financial benefits have been identified. Exhibit AG-1.13 includes the Part III project document filed by the Company providing the information discussed above.

Aside from the awkwardly worded project description and purported benefits, it is not clear why the Company would need to spend $8 million to develop a system to keep track of innovation items. It is difficult to understand how voluminous the number of innovations is at the Company that it cannot keep track of them through much less expensive means. It is also difficult to understand why this project is a priority program that should be done over the next two years, when the Company is challenged to improve its aging electric infrastructure in order to deliver more reliable service.

I recommend that the Commission reject the proposed capital spending over the two-year period from 2020 through April 2021. Exhibit AG-14 shows the specific capital spending disallowances of $5.3 million for the projected periods in this rate case.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF THE CAPITAL EXPENDITURES FOR THE DIGITAL ENGAGEMENT GROUP ESTABLISHMENT IT PROJECT.

A. The Company describes the Digital Engagement Group Establishment project as follows:

> The Digital Engagement Group (DEG) is a new organization dedicated to improving the Company's customer experience. During this period, capital investments will be made in three areas: 1) Hardware and software will be purchased to construct copies of our existing Customer system's production environments. Once implemented, these environments provide the DEG team with dedicated development and test systems. 2) The team will produce designs for customer system enhancements specifically targeted at improvements in the

> customer experience. Once completed and approved these designs will be implemented by the IT Customer Service Team in the form of projects or enhancements. 3) During the period the DEG Team will produce, at minimum, the Designs for the Transformational Web, the replacement Mobile application, and a solution allowing customers to track all of their interactions with the Company.

The benefits stated by the Company are that the DEG and this system will somehow improve the customer experience, but it is unclear what that means. No financial benefits have been identified. As stated above, the cost to develop this group and computer systems is $9.2 million to be spent during the year 2020. The Part III document filed by the Company and describing the information above is included in Exhibit AG-1.13.

The value of this program and the related $9.2 million capital expenditures is questionable at best. The Company has not adequately explained or justified what it means by customer experience, what it plans to accomplish specifically, why customers are interested in having a better customer experience, how many customers would benefit from this initiative, and why this is a major priority to be completed in 2020. It would seem that the $9.2 million would be better spent on improving electric infrastructure where frequent power outages are occurring.

Therefore, I recommend that the Commission remove the $9.2 million from forecasted capital expenditures for 2020. Exhibit AG-1.14 shows the disallowance amounts apportioned to the appropriate future periods for rate base calculation purposes.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF THE CAPITAL EXPENDITURES FOR THE SUCCESS-FACTORS PROGRAM.

A. The Company describes the SuccessFactors Program as follows:

> The current Compensation module is highly customized and expensive to maintain and is not integrated with the SuccessFactors platform. This strategic compensation management solution enables compensation professionals, business leaders, and managers to align compensation programs with business objectives, helping DTE model and manage competitive compensation programs.

The proposed total cost for this project for 2019 and through 2021 is $11.7 million. The Company describes the benefits from this capital program as enabling effective management of compensation programs by integrating the compensation management system with the SuccessFactors platform. No financial benefits have been identified. The Part III document on this project is included in Exhibit AG-1.13.

This is a very expensive project that could be pursued in a more cost-effective manner. Compensation systems are usually part of the Payroll system. It is not clear why the Company needs to spend more than $11 million to integrate a new compensation system within the SuccessFactors platform in order to align compensation programs with business objectives. Aligning compensation programs with business objectives is usually a process of compensation plan design at a high level, and not an execution function requiring complex computerized systems.

The Company has failed to adequately explain and justify the need and priority of this project versus more demanding projects to improve electric facilities and visible customer service. Therefore, I recommend that the Commission reject the inclusion of $9.1 million of capital expenditures in this rate case. Exhibit AG-1.14 shows the apportionment of this adjustment to the appropriate future periods for removal from rate base.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF THE CAPITAL EXPENDITURES FOR THE WEB PORTAL REBUILD AND TRANSFORMATION PROJECT.

A. The Company describes the Web Portal Rebuild and Transformation project as follows:

> DTE will invest in the Soteria SafeWorker Observations (SWO) application, our Corporate Safety Tracking system. The Company is firmly committed to the safety of our employees and our customers and holds Safety as a core value. As such, the Company views safety systems as a Non-Discretionary investment. The newest version of this system, Soteria 2.0, is now Cloud based and this investment will simplify the collection, tracking and analysis of safety data gathered by Company leadership through targeted electronic SafeWorker Observations. This observation data along with improvement opportunities is a cornerstone of the Company's ability to drive worker safety.

The proposed total cost for this project for 2020 and 2021 is $23.1 million. The Company describes the benefits as "Enhancements to the Soteria 2.0 will provide the company with forms to track safety data, rich data metrics in dashboard format, reports, analytics, graphs in an easy one stop shop for Corporate Safety, leaders and employees to track their area's safety compliance." No financial benefits have been identified. The Part III document on this project is included in Exhibit AG-1.13.

This project appears to be an expensive upgrade, at $23.1 million, to an existing system in order to report data in dashboard format with presentation in graphs and perhaps other enhanced reporting. These are niceties that do not necessarily have anything to do with preventing safety incidents. This system appears to be simply a data tracking and reporting system. Therefore, the statement that this is a "must-do" project to improve the Company's safety record is a red herring to gain approval of the project. If the Company wants to spend more than $23 million on a system upgrade, it has an obligation to show how safety will be improved and safety incidents will be prevented, along with financial benefits that justify the capital expenditures. The Company has not presented any of that.

Because of this lack of evidence and other more pressing priorities to spend capital on electrical infrastructure improvements, I recommend that the Commission remove $17.8 million of capital expenditures from the projected periods pertaining to this project. Exhibit AG-1.14 shows the apportionment of this adjustment to the appropriate future periods for removal from rate base.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF THE CAPITAL EXPENDITURES FOR THE BILL REDESIGN PROJECT.

A. The Company describes this project as a redesign of the customer bill so that key information will be in an easy to read format after doing industry research and receiving customer feedback.

The cost of the bill redesign is expected to be $7.0 million over the 2020 to 2021 timeframe. The Company stated as a benefit of the project the presentation of streamlined information and the reduction of paper, which would result in cost savings. It also identified as benefits the easy-to-read format of the new bill and the ability to accommodate bill presentation requirements for alternative rates and services. No financial benefits or cost savings were identified. The Part III document on this project is included in Exhibit AG-1.13.

The value of this project is questionable. In 2017, the Company completed the implementation of the Customer 360 system at a cost of more than $200 million. That system included a new customer billing system and improvements to customer billing and bill presentment. It is difficult to understand why, two years later, the Company is seeking to redesign the customer bill at an additional cost of $7.0 million when there are more pressing needs to rebuild electrical infrastructure. No matter how the Company designs its bill, it is a given that some customers will have confusion or dissatisfaction with the bill presentation. No specific evidence has been presented by the company to show that there is broad-based dissatisfaction or confusion with the format of the bill to justify spending $7 million over the next two years, particularly when there are far more pressing needs for capital.

Given the lack of evidence of a critical need to undertake this project, I recommend that the Commission disallow inclusion of $5.7 million in capital expenditures for this project for the projected periods. Exhibit AG-1.14 shows the apportionment of this adjustment to the appropriate future periods for removal from rate base.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF THE CAPITAL EXPENDITURES FOR THE PURCHASE TO PAY PROJECT.

A. The Company describes this project as a transformation of the Purchase to Pay (P2P) process through the implementation of Ariba, in order to improve the Company's ability to procure and manage inventory.

The cost of this project is expected to be $6.7 million over the 2019 to 2021 timeframe. The Company stated increased efficiencies in the supply chain and better integration of purchasing capabilities, along with work management, as benefits. Other stated benefits were from better scheduling and purchasing capabilities, which supposedly would also improve the gas and electric customer experience. How inventory procurement and scheduling would improve the customer experience is not clear. No financial benefits or cost savings were identified. The Part III document on this project is included in Exhibit AG-1.13.

Aside from the typical “buzz words” of enhanced technologies, better integration, greater efficiency, and customer experience, there are no quantifiable benefits presented by the Company to justify undertaking a project of this size. No information has been presented to show that there is a compelling need at this time to transform the P2P process, particularly when there are more pressing needs to upgrade electrical infrastructure that will more directly improve the customer experience through improved customer service and electrical power reliability.

In the project description document included in Exhibit AG-1.13, the Company states that it plans to “sunset” the current SAP system’s P2P functionality in 2025 by replacing it with the Ariba system. Given that time horizon, it appears that implementation of this system in 2021 is premature by at least four years.

Given the lack of evidence of a compelling need to undertake this project at this time and no financial justification, I recommend that the Commission remove $5.1 million of capital expenditures from the project periods for this project. Exhibit AG-1.14 shows the apportionment of this adjustment to the appropriate future periods for removal from rate base.

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF THE CAPITAL EXPENDITURES FOR THE FIXED BILL (WEATHER GUARD) PROJECT.

A. The Company describes the Fixed Bill (Weather Guard) project as follows:

> [Develop the system functionality to provide] customers with the option to pay the same fixed monthly payment, including an embedded risk premium, that is not subject to true-up regardless of variability in consumption, weather or commodity prices. Offers are renewed every 12 months and include an abuse clause to help limit changes in customer behavior. There will be a settlement for customers that leave prior to the end of contract clause.

The cost to develop this system functionality is expected to be $2.8 million in 2020. The Part III document on this project is included in Exhibit AG-1.13.

Company witness Eric Clinton sponsors the proposal to initiate a pilot Fixed Bill program in 2020. Later in my testimony, I discuss this proposal and my recommendation for the Commission to reject the Fixed Bill proposal. Therefore, the Commission should also reject the IT capital expenditures of $2.8 million for this project for the projected periods. Exhibit AG-1.14 shows the apportionment of this adjustment to the appropriate future periods for removal from rate base.

E. Capital Expenditures Adjustments - Summary

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

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

Summary of AG Disallowed Capital Expenditures		
		Amount (millions)
Contingent Capital Expenditures	$	17.7
Distribution Operations		
Emergent Replacement Programs		44.6
Customer Connections, Relocations, Other		27.4
Strategic Capital Programs		182.3
Power Generation		
Routine Projects		43.0
Non-Routine Projects		40.8
Information Technology		
Major Projects		54.9
Incentive Compensation		
Capitalized Amount		44.4
Total	**$**	**455.1**

Based on my analysis and information presented in my testimony above, the Commission should reduce the Company's proposed capital expenditures by $455.1 million and average rate base by $420.8 million, including working capital adjustments discussed below. Exhibit AG-1.11 provides additional details and calculations of these amounts.

V. Working Capital Adjustments

Q. DO YOU AGREE WITH THE COMPANY'S LEVEL OF WORKING CAPITAL AT $1.462 BILLION?

A. No. I propose that the level of working capital in this case be reduced by $74.3 million, to $1.388 billion, to reflect (1) the exclusion of $68.0 million of Accounts Receivable-REF Companies; (2) a $2.0 million correction to Accounts Payable-Associated Companies; and (3) reductions to the levels of Cash ($2.1 million) as well as Materials and Supplies ($2.0 million).

First, regarding Accounts Receivable from the REF Companies, in her response to Staff discovery request JSG 1.1, Company witness Uzenski stated that the Company should have excluded $68.0 million related to these receivable accounts. The Company erroneously included the balance related to these accounts receivable from 2018. Business dealings with the associated companies were discontinued in 2018. As such, the receivable amounts will not be a working capital factor in the projected test year.

Second, regarding Accounts Payable to Associated Companies, in response to staff discovery request TGW 2.2, witness Uzenski confirmed that this balance sheet item contained a transposition error that caused a $2.0 million overstatement of working capital.

Third, the balances for Cash, as well as Materials & Supplies, included by the Company in its working capital estimate were based upon the historic year end level at December

31, 2018 and not the average historical period balances. It is more appropriate and common practice to use an average balance over the historical period and not a balance at a moment in time. As such, I reduced the level of Cash by $2.1 million and the level of Materials & Supplies by $2.0 million.

The items discussed above result in a $74.0 million reduction of the Company's working capital estimate for the projected test year. Exhibit AG-1.15 shows the calculations to arrive at this adjustment amount.

VI. Cost of Capital

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

A. I recommend that the capital structure shown on page 1 of Exhibit AG-1.16 be used in this rate case. The first 3 lines of the exhibit under the Capital Structure heading show the projected long-term debt and common equity permanent capital of the Company for the test period ending April 2020. The permanent capital balances in this exhibit reflect a 50% long term debt and 50% common equity capital. These are the same ratios proposed by the Company in Exhibit A-14, Schedule D1. These capital structure ratios also reflect the capital percentages approved by the Commission in Case No. U-20162, which was the Company's previous general rate case.

Regarding the amount of short-term debt, I increased the $219.9 million proposed by the Company to $337.2 million to match the amount of short-term debt shown in the 2018 historical year. The increase in short-term debt of $117.3 million in the capital structure has been offset with an equal reduction in common equity and long-term debt.

Q. WHY DID YOU SET THE SHORT-TERM DEBT BALANCE IN THE PROJECTED TEST YEAR EQUAL TO THE AMOUNT IN THE HISTORICAL YEAR?

A. As shown on page 2 of Exhibit AG-1.16, the Company has used progressively greater amounts of short-term debt during the 2016 to 2018 timeframe. This is to be expected as DTEE grows its business and requires higher amounts of short-term debt to meet its sort-term capital needs. Although the Company continues to propose smaller amounts of short-term debt in its rate case filings (at least since U-18014), actual results since 2016 show that short-term debt has continued to increase over the past three years. Therefore, using the same amount of short-term debt used by the Company in 2018 for the projected test year is a reasonable assumption if not somewhat conservative.

Q. ARE THERE OTHER FACTORS SUPPORTING THE GREATER USE OF SHORT-TERM DEBT BY THE COMPANY IN THE FUTURE?

A. Yes. In response to a discovery question, the Company stated that in April 2019, the Company increased the size of its short-term credit facilities with financial institutions from $400 million to $500 million.[10] Along with the increased borrowing capacity, the

[10] DTEE response to discovery request AGDE 1.17.

fixed commitment fees paid to banks have increased from $787,000 in the historical period to $950,000 in the projected period. It seems reasonable then to expect some greater utilization of short-term debt going forward and into the forecasted test year. Nevertheless, taking a more conservative position, I have set the amount of short-term debt in the projected test year at the same level that the Company used in 2018.

Q. DID YOU CALCULATE THE DIFFERENCE IN REVENUE REQUIREMENT OF INCREASING THE SHORT-TERM DEBT BALANCE WHILE DECREASING COMMON EQUITY AND LONG-TERM DEBT?

A. Yes. The additional $117.3 million of short-term debt instead of more common equity and long-term debt, which have a higher cost, decreased the revenue requirement by approximately $7.0 million.

There is simply no need to burden customers with this additional cost, given the Company's historical use of higher levels of short-term debt and especially after the Company increased the size of its short-term borrowing facilities. In conclusion, the Company's proposed lower level of short-term debt for the projected test year is neither credible nor reasonable. The Commission should reject the Company's proposed capital structure with the lower short-term debt and instead adopt the capital structure I have proposed in Exhibit AG-1.16.

Q. DID YOU MAKE ANY OTHER ADJUSTMENTS TO OTHER 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 5.23%, which includes a return on common equity of 9.25%, as shown in Exhibit AG-1.16.

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

A. I have utilized the 4.31% rate proposed by Company witness Edward Solomon.

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 Solomon. 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-1.16?

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 5.23%.

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 taxes paid by the Company for calculation of the pretax weighted cost of 6.46% 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-1.17.

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, any potential changes in the risk profile of DTE Electric, and the state of the Michigan economy. While Exhibit AG-1.17 shows a calculated cost of common equity of 8.24% from the three approaches, I recommend an allowed rate of return on equity of 9.25% 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. I started with the 38 electric utility companies followed by the Value Line Investment Survey. From this group of companies, I removed seven companies, such as Duke, Exelon, and Southern Company, due to their considerably larger size. I also removed four companies with annual revenues of $1.0 billion or less. Next, I removed two companies whose dividends are not growing. Finally, I removed: (a) five companies who were recently involved in mergers or acquisitions; (b) two companies with large foreign investments; (c) three companies whose earnings declined significantly in 2017; (d) Edison International due to the California wildfire liability risk, and (e) DTE Energy. Exhibit AG-1.22 shows the initial group of electric utilities from Value Line and the process of removing certain companies that are not appropriate comparable companies to arrive at the proposed peer group,

The result of this process is the group of eighteen companies shown in Exhibit AG-1.18, all of which are of comparable size and business profile, and have growing earnings and dividends.

Q. HOW DOES YOUR PEER GROUP OF EIGHTEEN ELECTRIC UTILITIES COMPARE TO THE COMPANY'S PROPOSED PEER GROUP?

A. The Company has presented two peer groups. One is a larger peer group of 26 companies, which are electric utility companies. However, the Company has also sponsored another peer group of 11 companies consisting of gas distribution and water utility companies. I will address the propriety of this peer group later in my testimony.

The Company's electric peer group presented by witness Bente Villadsen consists of a group of 26 companies. This group includes fourteen of the companies in my proposed peer group, plus (a) six companies I removed due to size considerations; (b) PPL, Consolidated Edison and Entergy, all of whom experienced falling earnings in 2017; (c) Avangrid (with no dividend growth), Edison International (which has wildfire risk and thus dividend risk); and Southern Company which is facing major challenges constructing nuclear power facilities; and (d) DTE Energy.

Q. PLEASE COMMENT ON THE COMPANY'S SECOND PEER GROUP WITH NATURAL GAS AND WATER COMPANIES.

A. This peer group of 11 companies consists of four water companies and seven natural gas companies. Three of the four water companies are relatively small businesses with less than $500 million in annual revenues. In contrast DTEE had $5.3 million in revenues in 2018.[11] Two of the seven natural gas companies are also small utilities with approximately $700 million in annual revenues. As such, the small size of some of these companies makes this group of companies a very poor peer group.

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

A. The water industry is in a state of consolidation. American Water Works, the largest water company selected by witness Villadsen, is a well-known business consolidator with its

[11] Exhibit A-3, Schedule C1.

earnings growth highly dependent on achieving cost synergies by absorbing smaller companies.

According to Value Line, American Water Works is expected to achieve long-term earnings growth of 9.5%, primarily driven by acquisitions. Value Line's analysis of the water industry and American Water Works is included as Exhibit AG-1.24.

Some of the natural gas companies chosen by witness Villadsen have substantial non-utility businesses. In particular, Chesapeake Utilities has 55% of its revenues from unregulated businesses, such as propane, natural gas marketing and midstream services. In its analysis of the company, Value Line states that Chesapeake Utilities is expected to grow earnings at a 9% rate through 2024 with most of the growth coming from the non-utility part of the business.

Q. WHY DID WITNESS VILLADSEN INCLUDE A PEER GROUP WITH WATER AND NATURAL GAS COMPANIES?

A. In her direct testimony, she offers three reasons. The first reason is somewhat opaque and hard to reconcile with reality. On page 36 of her testimony, she states the following:

> *First, the electric industry is currently undergoing substantial changes, which means that initiatives in a specific state influences stock prices and analysts' evaluations along with more fundamental operating and market conditions. Because the changes are industry specific, I cannot select a sample that is completely free of such considerations. The OHRU [*Other Highly Regulated Utilities Proxy Group] *sample currently faces fewer state-specific initiatives and therefore I find these highly regulated utilities a compelling benchmark.*

The electric industry has been going through changes for many years. This does not mean that an appropriate peer group of companies that are going through similar changes is not an appropriate comparable group to use to establish the appropriate cost of capital. The peer group of 18 companies I have assembled achieves that objective without venturing into companies in the water and natural gas businesses.

Her other two reasons are (a) the need, in her view, to compare the electric industry to other similar risk benchmarks, and (b) using a peer group with similarities, such as the capital-intensive nature of the businesses, common regulators, and the "obligation to serve."

Although there may appear to be some similarities between electric utilities, natural gas and water utilities, there are more significant differences than similarities. Electric utilities generally are integrated companies with generation and distribution, while natural gas and water utilities are primarily distribution companies. Electric utilities also tend to be much larger companies with larger market capitalization, and therefore easier access to capital, which lowers their cost of capital. Additionally, electric utilities face more environmental regulation than natural gas and water utilities due to emissions from power generation. These differences more than overcome any superficial similarities that witness Villadsen may perceive.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S TWO PEER GROUPS?

A. Both peer groups suffer from significant shortcomings, which renders them unacceptable. With regard to the Company's proposed electric peer group, it contains four electric utilities that are very small in size. These small companies represent 15% of the peer group and are not a good fit with DTE Electric. The small size and market capitalization of these companies makes the trading of their common stock and public debt less liquid, increasing the cost of capital. Additionally, two of the other companies included in witness Villadsen's electric peer group are Southern Company and Edison International. Southern Company continues to face financial challenges with the construction of two nuclear plants and has been selling assets to pay for cost overruns. The risk profile of this company is not comparable to DTE Electric or other utilities in the peer group. Regarding Edison International, the company reported in its Form 10K filed with the Securities and Exchange Commission that it set up a reserve in the fourth quarter of 2018 of $1.8 billion after-tax associated with wildfire risks prior 2019. Wildfires were a major factor that forced Pacific Gas & Electric into bankruptcy. For these and other reasons discussed above, this electric peer group is not an appropriately comparable group of utility companies and should be disregarded.

With regard to the alternative OHRU peer group of natural gas and water utilities, this peer group veers off even further from a truly comparable group of companies as discussed earlier in my testimony. Smaller size companies in different businesses in natural gas and water distribution are not comparable to the electric business. The Commission should reject both this alternative peer group as well as the Company's deficient electric peer group for the reasons discussed above.

Discounted Cash Flow (DCF) Approach

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

A. The DCF approach is based on the proposition that the price of any security reflects the present value of all future cash flows (dividend flows) from the security discounted at a single discount rate, which in the case of common stocks, is the required return of equity. Expressed mathematically, the resulting equation can be reconfigured to solve for the required rate of return 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-1.18. 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 September 30, 2019. The annual dividend in column (d) is the projected dividend level for 2020 as projected by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on Value Line projections of earnings per share through the 2022 – 2024 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 8.31% for the proxy group.

Witness Villadsen presents her simple DCF results in summary form on page 56 of her testimony, which are 9.9% for her electric peer group and 11.7% for her water/natural 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 a normal DCF analysis and then runs the results through an ATWACC process to derive a higher DCF cost of common equity.

Witness Villadsen's initial results for her DCF analysis are the last two data items in column (3) of Exhibit A-14, Schedule D5.7 page 1, which are 8.6% for her electric peer group and 9.4% for her water/natural gas peer group. Ultimately these results are used to develop the ATWACC in column 10, which is then repeated on Schedule D5.8 column (1); and used to derive the overall ATWACC DCF equity result. The following table simplifies this complex process.

	Electric	Water/Gas
Initial Calculation of DCF Cost of Equity	8.6%	9.4%
Upward Adjustment – ATWACC Process	1.3%	2.3%
ATWACC DCF ROE	9.9%	11.7%

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

A. The key factor causing the escalation in the ROE is the high stock market 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, higher 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 been able to cite only a hand-full of instances where the ATWACC approach has been used. These instances pertain to (1) property taxation disputes in Colorado; (2) Florida's regulation of small water companies; (3) a valuation dispute before the FERC; and (4) revenue adequacy hearings for railroads, as well as a revenue adequacy hearing involving Alabama Power related to a special customer rate. There are no known cases where a state regulatory commission in the United States has endorsed the ATWACC approach in setting the cost of common equity 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 as 8.5%. 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:

$$k_e = R_f + (B \times R_p) \quad \text{where}$$

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-1.19 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-1.19 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) Historical Market Risk Premium (R_p) information of 6.91% 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 early October 2018 is approximately 2.2%. However, sentiment in the market is fairly universal that interest rates will rise assuming continued economic expansion in the United States. In this regard, interest rate projections available from IHS as of October 2019 indicate ten-year U.S. Treasury bonds (currently yielding 1.8% as of early October 2018) could reach 2.7% in 2021, which is the end of the projected test year in this case. To this rate, I have added 0.50% to reflect the current spread between 30-year and 10-year U.S. Treasuries which results in a projected 30 Year Treasury Bond of 3.20% (the projected risk-free rate).

As shown in Exhibit AG-1.19, I have added the beta adjusted peer group risk premium of 4.07% to the 3.2% risk-free rate to arrive at the 7.27% ROE rate under the CAPM approach.

Q. PLEASE ASSESS THE CALCULATIONS OF THE CAPM COMMON EQUITY COST RATES OF 8.3% TO 9.1% PERFORMED BY WITNESS VILLADSEN FOR HER ELECTRIC PEER GROUP.

A. In Figure 17 on page 52 of her direct testimony, witness Villadsen presents 6 different CAPM estimates for the electric peer group and another 6 CAPM estimates for her water/natural 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 the ATWACC process which, as I discussed under the DCF section of my testimony, leads to faulty and inflated results. Witness Villadsen also presents two scenarios in the table in Figure 17. Scenario 1 starts with the development of CAPM results for each peer group company on the basis of using a market risk premium, or MRP, of 6.9% and a projected 20-year U. S.

Treasury bond rate of 3.75% 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 7.9% MRP, which is 100 basis points higher than she used in Scenario 1, but uses a 3.50% risk free rate. The use of an MRP rate of 7.9% versus 6.9%, which is the historical average rate from 1926 to 2018, is highly unconventional and solely based upon witness Villadsen's opinion that MRP rates have escalated since the 2007-2008 financial crisis. The following table reconciles the differences between my CAPM ROE rate of 7.27% and witness Villadsen's calculated ROEs, and shows the impact of the ATWACC conversion process.

Reconciliation of AG CAPM to Fig. 17 - Line 1	Scenario 1	Scenario 2
Attorney General CAPM ROE	7.27%	7.27%
Higher Risk Free Rate Per Company	0.55%	0.30%
Escalate MRP from 6.9% to 7.9%	0.00%	0.63%
Sub Total	7.82%	8.20%
Effect of ATWACC Conversion	0.88%	0.90%
Villadsen Figure 17 (Page 52 of Testimony)	**8.70%**	**9.10%**

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 0.3% to 0.7% under the ECAPM. This adjustment is subjective, unconventional, and not supported.

In her testimony, witness Villadsen did not specify if the ECAPM was utilized to set rates in other jurisdictions. However, in Case U-18999 the witness for the Company's affiliate, DTE Gas Company, was able to identify only the Alberta Utilities Commission of Canada.[12] In its order of October 7, 2016, the Alberta 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 and added this statement: **"*Consequently, the Commission will not rely heavily on the ECAPM results in this proceeding…"*** (Emphasis added).

Witness Villadsen's various methods used to calculate the cost of equity capital are highly unconventional, not generally accepted, and are based in part upon her opinion that market 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

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

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.

<u>Utility Risk Premium Approach</u>

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 Bond (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-1.20 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 9.08%. To arrive at this result, I have used the 4.25% historical spread of electric utility common stock returns relative to utility bonds. Also, I have used a 1.69% (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 UNDER THE "RISK PREMIUM MODEL ESTIMATES."

A. Beginning on page 57 of her testimony, Witness Villadsen states that she compared the authorized ROEs from electric utility rate case decisions from 1990 to 2018 to 20-year U.S. Treasury bonds. According to her testimony, she performed a regression analysis to the data and found a strong relationship between ROEs and interest rates. She also observed that ROE rates have fallen more slowly than Treasury bond interest rates. Based on her model results, she concluded that a ROE of 10.2% to 10.3% for a vertically integrated electric utility would be appropriate, based on 20-year U.S. Treasury rates of 3.50% to 3.75%. Interestingly, the current interest rate for 20-year U.S. Treasury bonds is 2.1%, or about 1.6 percentage points below her assumed rates. Using the current 20-year U.S. Treasury rate would result in a proposed ROE of approximately 8.6%.

What is troubling about this analysis is that it lacks any comparison of actual returns achieved on utility common stocks (via price appreciation and dividends) 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 Michigan economy has completely recovered from the most recent recession and interest rates are stable to declining thanks in part to the monetary policy of the Federal Reserve Bank. These factors have placed the Company in a better position with respect to sales levels, interest rates, and uncollectible sales amounts. The Company's access to the capital markets is strong as witnessed by DTE Electric's issuance in February 2019 of $650 million of 30-year long-term debt at a rate of 3.95%. 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 the June to August 2019 period issuing approximately $1.5 billion of new long-term debt with maturities of three to ten years with rates in the 2.5% to 3.4% range.

Accordingly, the Company's recommendation that the authorized rate of return on common equity should be increased to 10.50% 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 8.25%.

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE GRANTED IN RECENT YEARS?

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 9.6% in the January 2018 through June 2019 period.

Exhibit AG-1.21 shows the more recent ROE rates granted by state regulatory commissions for electric utilities during 2018 and 2019 and published by Regulatory Research Associates, a respected and independent regulatory research firm. More than 80% of electric decisions rendered involved ROE rates averaging 9.5% during this eighteen-month time frame. With declining interest rates in the near term, it is likely that ROE rates granted by regulatory commissions will continue to decline

Page 1 of Exhibit AG-1.21 shows the most recent ROEs assigned to the peer group companies through June 2019. The average ROE rate for this group is 9.58%. Recent ROE decisions for the group have trended down, with rate decisions as low as 8.69 in Illinois. The large group of utilities shown on pages 2 and 3 of this exhibit shows similar trends with ROE rates well below 10% with only few exceptions. These pages also include information regarding debt financing subsequent to the rate orders. It is clear from this information that the capital markets have continued to provide debt capital at competitive interest rates to electric utilities with authorized ROEs well below 10%.

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

A. In Exhibit AG-1.17, I have summarized the cost of equity rates from the three methods I used. The range of returns for the industry peer group is from 7.27% at the low end, using the CAPM approach, to 9.08% at the high end using the Utility Risk Premium 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 8.21%. In this regard, on line 4 of Exhibit AG-1.17, 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 8.19% for the average of the industry peer group. However, I am recommending a higher ROE rate of 9.25% for DTE Electric Company for the reasons explained below.

First, long-term interest rates are currently at a low level, and although they certainly justify ROEs well below 9.25%, they could negatively impact the long-term cost of common equity if they were to increase significantly in the coming years. As such, while the cost of common equity I have calculated is an accurate assessment of expectations for the forecasted test year, significantly higher U.S. Treasury interest rates at or above the 3.2% level assumed in this rate case analysis may produce a different result should such higher interest rates become a reality. In this regard, a potential 10% correction in utility stock prices due to higher interest rates would produce a 0.30% to 0.40% increase in the cost of capital under the DCF approach.

Second, the Company's own witness calculated the cost of common equity for the electric peer group, before being adjusted upward for the ATWACC methodology, at 8.6% under the DCF approach and at 8.2% (its highest rate) under scenario 2 of the CAPM methodology.

Third, I understand that the Commission may be reluctant to set a ROE for the Company at the true cost of equity of 8.19%. Regulatory commissions around the country have granted ROEs averaging 9.5% to electric utilities during 2018 and 2019, with only few cases granted at the 10.0% level. In fact, approximately 50% of the reported ROE decisions in electric utility rate cases reported by "Regulatory Focus" during this time frame are well below the average rate of 9.5%. Therefore, my recommended ROE rate of 9.25% in this case is reasonable and fair, if not generous, as a gradual transition to the true cost of equity.

Q. DO YOU HAVE ANY OBSERVATIONS WHY THE COST OF EQUITY FOR DTE ELECTRIC IS 8.19% AND CONTINUES TO DECLINE FOR ALL UTILITY COMPANIES?

A. Yes. In conjunction with the recession of 2008-2009, the Federal Reserve reduced interest rates significantly to spur economic activity. The result has been a long-protracted period of low interest rates and low inflation, which has provided low cost of capital and has boosted the U.S. economy. While some financial experts have argued that the Federal Reserve easing of interest rates was a temporary phenomenon, it is now in its 10th year and continuing.

In other words, low interest rates are no longer temporary. They persist and need to be fully reflected in the determination of return on equity rates. Interest rates have a direct correlation to the cost of common equity because those two sources of capital compete for investors' funds. The long-term cost of debt and equity capital has declined significantly since 2010 and must be recognized by regulatory commissions in setting appropriate ROE rates. ROE rates currently granted by many regulatory commissions are still significantly above the true cost of equity for those utilities and they unnecessarily increase customer rates.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE OF 9.25% 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, certain rate case applicants have raised arguments that they should receive a ROE 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 2 and 3 of Exhibit AG-1.21 show several utilities that have accessed the capital markets at competitive interest rates since receiving a ROE near or below the average rate of 9.50%.

Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs below 10%. On the contrary, stock investors continue to migrate to utility stocks, recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-1.23 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 as low as 8.69%. Yet this group of companies has an average Market to Book common equity value ratio of nearly 2.3 times.

This information is provided to dispel the myth that the Company must receive a ROE at or above 10%, 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 well below 10.0%. Therefore, this issue is another “red herring”.

Q. IF THE COMMISSION APPROVES A 9.90% COST OF COMMON EQUITY IN THIS CASE AS IT DID RECENTLY IN OTHER RATE CASES, WHAT IS THE COST TO CUSTOMERS COMPARED TO AN ROE OF 9.25%?

A. Assuming the Commission grants a 9.90% ROE in this case versus a 9.25% ROE, the additional cost to customers is approximately $61.6 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 a ROE of no more than 9.25%.

VII. 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 is forecasting total electricity sales of 46,007 Gigawatt hours (GWh) for the May 2020 to April 2021 test year. This represents an overall decrease of 673 GWh, or 1.4%, in comparison to the weather-normalized actual sales of 46,680 GWh in 2018.[13] From reviewing Mr. Leuker's testimony and exhibits, as well as responses to data requests, it appears that most of the decline is attributed to (1) the decline in residential and commercial sales, primarily from forecasted energy efficiency, and (2) the decline in industrial sales.

After reviewing the Company's assumptions and projections, I have determined that the forecast for residential, and commercial and industrial (C&I) sales is significantly understated. In Exhibit AG-1.25, I have analyzed the historical temperature-normalized

[13] Exhibit A-5, Schedule E1, pages 4, for 2018, and Exhibit A-15, Schedule E1, page 1, for the projected test period. Sales for 2018 and projected period exclude sales to former customers of the Detroit Power Lighting Department (PLD) which are accounted for under a separate regulatory arrangement.

residential and C&I sales for the five years from 2014 to 2018 and I have compared them to the forecasted sales for 2019, 2020, and the projected test year.

In addition, I have calculated weather-normalized sales per residential and C&I customer for the same years. During this five-year period, average sales per residential customer have ranged from a high of 7,776 kWh in 2014 to a low of 7,498 kWh in 2018. Sales per customer in between those years have generally seen a slight decline from year to year. The average rate of change for the 3- year and 4-years ended 2018 is a similar decline of 0.91%.

In contrast, the Company is projecting a decline in average residential customer sales for 2019 of 0.5% from 2018 and a further decline of 1.7% in 2020 over 2019. For the April 2021 ending test year, the Company is projecting average sales per residential customer of 7,298 kWh, which is a 2.2% decline from average sales per customer of 7,463 kWh in 2019.

For C&I customers the rate of historical decline per customer over the 3-year and 4-year period is 0.49% and 0.71%, respectively. The rate of decline per C&I customer for the projected period diverges from the historical periods by a wide margin. The decline in 2019 sales per customers from 2018 levels is 1.1% with an additional decline of 1.5% in 2020. For the projected test year, average sales per C&I customer decline 1.9% from the 2019 level. This rate of decline is more than twice the average rate of decline during the five years ending December 2018. This significant and sudden drop in sales for the projected test year raises concerns about the accuracy of the Company sales forecast.

The decline in the forecasted average residential sales per customer during the projected test year seems to be mainly attributable to the Company's assumption of higher energy efficiencies within the sales forecasting model and the forecasted growth in Distributed Generation sales offsets. This assumed large rate of decline is not supported by the historical 3-year or 4-year compound average rate of decline in residential and C&I sales per customer.

In discovery, the Company was asked to identify the amount of forecasted sales reductions from energy efficiency or Energy Waste Reductions (EWR) and how it calculated those reductions in sales. In response, the Company identified 703 GWh of sales reductions in 2019, 759 GWh for 2020 and 818 GWh for 2021. From the 2020 and 2021 reductions, I have calculated sales reductions of 779 GWh pertaining to the projected test year.

In response to discovery, the Company also stated that its sales forecast assumes EWR sales reduction of 1.65% for 2020 and 1.75% in 2021. According to the discovery responses, the regression forecasting model captures the historical EWR reduction rate of 1.50%, plus it adds the incremental EWR sales reductions to get to the EWR program targets of 1.65% and 1.75% forecasted for 2020 and 2021. Exhibit AG-1.26 includes the discovery responses with this information.

Whether the Company is using the historical EWR sales reductions rate of 1.5% or the higher projected rates of sales decline in the regression model or subsequent adjustments made to the model, these assumptions overstate the actual rate of decline experienced over the past three to four years. At most, approximately half of those rates of decline in sales has been experienced during the 2014 to 2018 period. This means that either the targeted EWR or energy efficiency targets are not actually being achieved or something else is partially offsetting the EWR sales declines. In either case, the sales for the projected test year are significantly understated.

Q. ARE THE PROJECTED SALES OFFSETS FROM DISTRIBUTED GENERATION HAVING A SIGNIFICANT IMPACT ON THE SALES FORECAST?

A. Yes, to some degree. According to the information provided by the Company in discovery and included in Exhibit AG-1.26, Distributed Generation (DG) sales offsets for the projected test year have been forecasted at 102 GWh. These sales offsets represent approximately 0.2% of the combined residential and C&I sales for the projected test year. According to Mr. Leuker's direct testimony and responses to discovery, the Company apparently does not have sufficient historical information about DG to accurately forecast how much its customers' self-generation will reduce future sales. Instead, the Company has used DG growth assumptions based on a nation-wide forecast obtained from the Energy Information Administration's (EIA) 2018 Energy Outlook report.

The rates of growth of 9% for residential DG and 6% for non-residential used by Mr. Leuker likely reflect areas of the country where DG evolved more quickly than in Michigan. Therefore, such broad assumptions are not likely applicable to DTEE's customer base. In discovery, the Company was asked to explain why these growth rates apply to its customers. In its response, the Company simply pointed to the EIA report with no further explanation. The discovery response is included in Exhibit AG-1.26.

More troubling is that the forecast of DG sales offsets provided by the Company shows a much more aggressive growth pattern than the 6% to 9% stated by Mr. Leuker in his testimony and in response to discovery. Discovery response STDE-2.1b, included in Exhibit AG-1.26, shows that DG volumes have been forecasted at 126 GWh by 2021. This represents an increase of 114% from the amount of 59 GWh in 2019, or an average increase of nearly 60% per year over the two-year period. Such a growth trend over a two-year period is not credible. This incredible growth trend, combined with the exaggerated EWR sales reductions discussed earlier, render the Company's sales forecast for the projected test year unreliable.

Q. ON PAGE 23 OF HIS DIRECT TESTIMONY, MR. LEUKER DISCUSSES THE ACCURACY OF THE COMPANY'S FORECASTING MODEL. DO YOU HAVE ANY OBSERVATIONS?

A. Yes. Mr. Leuker boasts about the variance of the forecasts over the most recent five years averaging approximately 1% from actual. Although on the surface this may appear to be a major accomplishment, it is important to keep in mind that a 1% variance in sales forecasting can result in a significant impact on sales revenue. This impact is particularly acute when compounded over multiple years, as is the case in this rate case, where the forecast is prepared in early 2019 for a projected test period that ends two years hence.

Furthermore, some of the variances shown in Exhibit A-15, Schedule E5, are more than 2%. As an example, a 1% to 2% understatement of residential sales compounded over a two-year period can impact forecasted sales revenue between $20 million to $30 million.

Q. **HAVE YOU PERFORMED AN ALTERNATIVE CALCULATION TO DETERMINE A MORE REALISTIC FORECAST OF RESIDENTIAL AND COMMERCIAL SALES AND THE RELATED REVENUE FOR THE PROJECTED TEST YEAR?**

A. Yes. In Exhibit AG-1.27, I have taken the weather-normalized average sales per customer of 7,498 kWh for 2018 and applied the actual 4-year average decline rate of 0.91% for 2019 and 2020, plus a prorated portion of this decline rate for the four months in 2021 to arrive at the projected average sales per customer of 7,361 kWh for the projected test year. Then, I multiplied this level of sales per customer by the number of customers forecasted by the Company for the test year. This calculation results in a residential sales forecast of 14,851,842 MWh. My forecast is 127,842 MWh higher than the Company’s residential sale forecast of 14,724,000 MWh. The higher forecasted sales result in incremental revenue of $7,809,889.

For C&I customers, I took a similar approach using the average compound rate of sales decline of 0.71%, and calculated an increase in sales of 494,240 MWh. However, instead of using the entire increase in sales for all C&I customers, I limited my revenue adjustment to only commercial customers in General Service Rate Schedule D3. Restricting my adjustment to sales for only these customers is a conservative step and considers the declines in industrial sales projected by the Company. Actual sales to General Service D3 customers in 2018 represented 22.8% of all sales to C&I customers. I used this percentage to allocate the total increase in sales volumes to General Service Rate Schedule D3 sales. The resulting incremental sales of 112,687 MWh pertaining to this customer group increased forecasted test year revenue by $4,356,464. The calculations to arrive at this amount are shown in Exhibit AG-1.28.

The combined incremental revenue for residential and commercial sales is $12,166,353.

I recommend that the Commission adopt my residential and commercial sales forecast and reflect the additional revenue I have calculated in determining an appropriate revenue deficiency for the Company for the projected test year. Exhibit AG-1.29 shows the sales billing determinants reflective of my sales adjustments.

VIII. O&M Expenses Adjustments

Q. **WHAT AMOUNT OF O&M EXPENSE DID THE COMPANY INCUR DURING 2018 AND WHAT IS THE LEVEL OF PROJECTED EXPENSE REQUESTED BY THE COMPANY FOR THE 12 MONTHS ENDING APRIL 2021?**

A. As shown in Exhibit A-13, Schedule C5, the Adjusted Historical Test Period expense level for 2018 is $1.269 billion. The Company has projected that O&M expenses will increase to $1.353 billion during the test year ending April 2021. The Company's projected expense level represents an increase of $84.3 million, or 7% over the historical level.

A. O&M Expense Inflation Adjustments

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED INFLATION ADJUSTMENTS TO O&M EXPENSE FOR THE PROJECTED TEST YEAR

A. Approximately $69.8 million of the increase in O&M expense for the projected test year represents inflation increases estimated by the Company based on a blend of the Consumer Price Index-Urban index (CPI) and 3% forecasted annual wage increases for union, non-union, and contract employees. Use of this "blended rate" has been rejected by the Commission in prior general rate cases.

More importantly, and contradicting some of the Company's testimony in this case, DTEE has not experienced across-the-board inflation pressure on its operating costs. In fact, according to Company witness Michael Cooper, actual O&M costs have remained well below the inflation trend line from 2009 to 2018.[14] It is therefore difficult to understand why the Company would project inflation-related cost increases for 2019, 2020, and the four months in 2021.

The Company has also been very vocal in stating that investments in technology will result in the reduction of O&M expenses. Yet, customers now must pay higher rates due to forecasted increases in O&M costs. The Company has not provided any evidence that its operations are facing inflationary cost pressures that it cannot manage in the course of operating its business. It is more than likely, based on historical data, that the proposed $69.8 million in inflation cost increases will not happen. The Company will likely continue to manage its operations to offset the low level of forecasted inflation with increased operating efficiencies and cost cutting.

I am aware of the fact that in prior rate cases, the Commission has allowed inflation cost increases for O&M expenses. However, the Commission also has rejected blended inflation cost factors that include internal salary increases as proposed by the Company in this case. **As a matter of policy, it is not advisable to allow utilities to escalate costs for forecasted future inflation. It becomes a self-fulfilling prophecy to increase future costs with inflation increases which then fuel and justify further inflationary trends. The Commission should only grant inflation cost increases when those increases are actually experienced and are likely to occur, and not because it has been past practice**

[14] Michael Cooper revised direct testimony at page 52.

to do so. In this case, the evidence is clear that inflation cost increases are not warranted or necessary.

In the discussion that follows about the O&M expense projected for Distribution Operations, and Steam, Hydraulic & Other Power Generation, I will demonstrate that operation and maintenance expenses for 2019 are running well below the projected levels and below the proposed inflation cost adjustments. These results appear to be representative of the remaining operations and cost centers of the Company where inflation cost adjustments were proposed. As such, it is reasonable to conclude that inflation is not impacting the operation and maintenance expenses of the Company, and no such adjustments should be approved by the Commission.

B. Alternative Inflation Adjustment

Q. IF THE COMMISSION DECIDES TO ALLOW SOME FUTURE INFLATIONARY COST ADJUSTMENT, SHOULD IT ACCEPT THE COMPANY'S PROPOSED INFLATION RATES?

No. As noted above, in Exhibit A-13, Schedule C5, the Company recommends the inclusion of $69.8 million for inflation increases. To compute this inflation amount, the Company uses the composite rates it determined in Exhibit A-13, Schedule C5.15. The exhibit shows that a 3% inflation rate is estimated for Company labor costs (50.6% weighting) and contractors' costs (34.9% weighting). For the remainder of its O & M costs (14.6%), the Company has escalated this component by the CPI-Urban index rates of 2% to 2.3% for the 2019 to 2021 period. The result of these calculations is a set of composite or blended projected rates of inflation of 2.8% for 2019, and 2.9% for 2020 and 2021.

The blended rates are a creation of the Company. The Company controls the rate of wage increases it grants to its employees, including union employees, through collective bargaining negotiations and in contractual arrangements with contractors. It truly becomes a self-fulfilling prophecy for the Company to estimate and recover inflationary cost increases of 3% that it can then grant to its employees and contractors. It is important for the Commission to encourage fiscal restraint. Therefore, such internally projected inflationary cost increases should not be granted.

The Commission in prior rate cases has been persuaded to grant inflationary cost increases equal to the CPI-Urban index. In this regard, if the Commission decides to again use the CPI-Urban index, it should use the most recent information available. The CPI-Urban index inflation rates proposed by the Company are now stale. Exhibit AG-1.30 includes a copy of the CPI-Urban index inflation rates from IHS Markit for 2019, 2020 and 2021. These rates are 1.9% for 2019, 2.1% for 2020 and 1.8% for 2021. These rates are generally lower than what the Company has proposed.

C. Distribution Operations

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED O&M EXPENSE LEVEL FOR ITS DISTRIBUTION OPERATIONS?

No. As shown in Exhibit A-13, Schedules C5.6, the Company is proposing $336.5 million of O&M expense for the projected test year for its Distribution operations. The Company's adjusted O&M expenses for these operations in 2018 was $313.2 million. To this cost level, the Company added $21.3 million in projected inflation adjustments and also applied additional cost adjustments of $2.0 million for other items. The net result is a spending level of $336.5 million.

Q. ARE THE YEAR-TO-DATE SEPTEMBER 2019 O&M EXPENSES FOR DISTRIBUTION OPERATIONS CONSISTENT WITH THE INFLATIONARY COST INCREASES PROPOSED BY THE COMPANY FOR 2019 AND FUTURE YEARS?

No. Actual O&M expenses for Distribution operations for year to date September 2019 are $249.6 million, and are running $27.2 million below the Company's forecasted amount of $277.1 for the same nine months. The variance is nearly 10% below the forecasted amount. Exhibit AG-1.31 shows this information. The exhibit also shows that the variance is across all major expense items. This is further confirmation that the Company is not experiencing inflationary cost pressure reflected in its forecasted O&M expense amount for 2019 and is not likely to experience any such inflationary cost increases in future years.

Q. ARE YOU PROPOSING OTHER ADJUSTMENTS TO THE O&M EXPENSE FOR DISTRIBUTION OPERATIONS?

A. Yes. I propose two additional disallowances. The first pertains to retroactive inflation cost increases calculated in the normalization of storm and non-storm restoration costs. The second pertains to higher O&M expense for Tree Trimming or Vegetation Management.

Q. PLEASE DISCUSS YOUR PROPOSED DISALLOWANCE OF RETROACTIVE O&M INFLATION ADJUSTMENTS TO STORM AND NON-STORM RESTORATION COSTS.

A. On line 19, column (e), of page 1 of Exhibit A-13, Schedule C5.6, the Company has included an adjustment of $29.0 million to reflect the normalization of storm and non-storm restoration costs. The purpose of the adjustment is to normalize erratic variances in storm and non-storm restoration costs from one year to the next, and to establish the 2018 historical O&M expense base on which the Company adds future inflationary costs increases to arrive at the forecasted test year O&M expense. The source of the Company's restoration cost adjustment is line 18, column (j), from page 2 of Exhibit A-13, Schedule C5.6.

In this page of the exhibit, the Company has retroactively increased the actual historical restoration costs for inflation. As discussed earlier in the capital expenditures section of my testimony pertaining to Emergent Capital Programs, it is simply an unsupported fabrication to inflate historical costs. Whatever inflation was experienced in those prior years is already reflected in the actual amounts. There is no need to add more inflation to bring the amounts to a present point. Although I agree with the five-year normalization approach to forecast storm and non-storm restoration expense for future years, it should be done using actual incurred expenses from prior years, as opposed to recast numbers with additional assumed costs for prior year inflation.

Without the retroactive inflation increases, the normalization adjustment is $23.9 million, or $5.1 million lower than the amount calculated by the Company. Therefore, I recommend that the Commission reduce the Company's forecasted O&M expense for Distribution operations by this amount. The calculations that support the $5.1 million disallowance are shown in Exhibit AG-1.32.

Q. PLEASE DISCUSS YOUR DISALLOWANCE OF HIGHER TREE TRIMMING EXPENSE PROPOSED BY THE COMPANY FOR THE PROJECTED TEST YEAR.

A. In column (j) of Exhibit A-13, Schedule C5.6, the Company has included an adjustment of $2.6 million pertaining to the $95.1 million of tree trimming base expense that the Commission approved in Case No. U-20162. This base amount is in addition to the Tree

Trimming Surge program funding approved by the Commission for the first three years of the program from 2019 through 2021. The adjustment of $2.6 million to the base tree trimming expense is calculated in Exhibit A-13, Schedule C5.6.1. In this exhibit, the Company simply adds annual inflation adjustments to the $95.1 million base amount for the period from May 2020 to April 2021.

This is another effort by the Company to increase the base funding of the tree trimming program by adding arbitrary cost inflation adjustments. The Commission set the limit for the base amount of tree timing expense for the 2020 test year at $95.1 million in Case No. U-20162. There is no reason to further increase that amount at this point until the Company provides additional evidence that more funding is needed above what was authorized in Case No. U-20162 for the base amount and the surge program.

Therefore, I recommend that the Commission remove the increase of $2.8 million to O&M expense for the projected test year.

Q. IN HER DIRECT TESTIMONY, COMPANY WITNESS HEATHER RIVARD REQUESTS THAT THE COMMISSION APPROVE AN EXTENSION OF FUNDING FOR THE SURGE PROGRAM TO THE YEAR 2022. DO YOU AGREE?

A. No. There is no need to further expand the program at this point, as the Company requests. The Commission approved a three-year period of funding for this costly program in order to ascertain if the surge program was achieving the claimed benefits, before approving a longer-term program. Nothing of significance has changed since the Commission decision in May 2019 that justifies extending approval for another year through the year 2022. The main reason that Ms. Rivard offers in her direct testimony is that tree trimming contractors may go to other states if there is no assurance that the DTEE tree trimming surge program will continue through 2022.

This claim is perplexing, because in response to discovery DTEE disclosed that the current contracts with tree trimming contractors expire on January 1, 2020 and the Company is currently negotiating new three-year contracts with contractors that will begin in January 2020.[15] These contracts would span through January 2023. The new contracts should remove any concerns about not having contractors for the year 2022. Furthermore, if the Company strongly believes that over the coming three years the surge program has achieved the benefits claimed in Case No. U-20162, it can proceed with the required amount of surge spending for 2022. The Company can later request inclusion of those costs in the regulatory asset for future recovery in a subsequent rate case. If the Company is able to make a convincing case before the Commission that the costs were reasonable, prudent and achieved the desired outcome, it should be able to recover those costs.

At this time, there is not sufficient evidence to assess the merits of a program that was approved only a few months ago. Therefore, I recommend that the Commission deny the requested extension of funding for the surge program through 2022.

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[15] DTEE response to Staff discovery request STDE-4.22.

D. Steam, Hydraulic & Other Power Generation

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED O&M EXPENSE LEVEL FOR ITS STEAM, HYDRAULIC AND OTHER POWER GENERATION OPERATIONS?

No. As shown in Exhibit A-13, Schedules C5.1, C5.4 and C5.5, the Company is proposing total cost levels of $304.8 million for its Steam, Hydraulic and Other Power Generation operations. The Company's adjusted O&M expense for these operations in 2018 was $298.1 million. To this cost level, the Company added $20.2 million in projected inflation adjustments, and applied reductions of $13.5 million due to certain generating plant retirements and operational modifications. The net result is a spending level of $304.8 million with $276.7 million applicable to Steam Generation, $11.3 million for Hydraulic Generation, and $16.8 million for Other Power Generation.

The O&M expense levels discussed above for these operations over the 2014 to 2019 period are shown in Exhibit AG-1.33. The information in this exhibit shows a 13.6% decline in O&M expense from 2014 to 2019 on an annualized basis. This declining trend reflects the reduction in operating costs from retirement of some coal plants and achieved operating efficiencies. The trend is likely to continue into future years as the Company continues to retire additional coal-burning power plants.

Q. ARE THE YEAR-TO-DATE SEPTEMBER 2019 O&M EXPENSES FOR STEAM, HYDRAULIC AND OTHER POWER GENERATION OPERATIONS

CONSISTENT WITH THE INFLATIONARY COST INCREASES PROPOSED BY THE COMPANY FOR 2019 AND FUTURE YEARS?

In discovery, the Company was asked to provide the monthly forecasted O&M expenses for Steam, Hydraulic and Other Power Generation operations for 2019, along with the actual O&M expenses for year to date September 2019. In response, the Company provided the actual expenses for the first 9 months of 2019, but did not provide the monthly forecasted amounts for 2019.[16] Therefore, a direct year to date comparison cannot be made. However, when annualized, the year to date September 2019 O&M expenses show a spending level of $265.7 million for 2019, or 11% below the 2018 level. This information is shown in Exhibit AG-1.33 and summarized in the table below.

	Actual 2019 Vs. 2018 Expense Levels			
Millions of Dollars	**Steam**	**Hydraulic**	**Other Pwr.**	**Total**
Actual Year to Date September 2019*	$181.8	$6.5	$11.0	$199.3
Annualized Level for 2019 (Sep Actual x 1.333)	**$242.3**	**$8.7**	**$14.7**	**$265.7**
2018 O&M Expense	**$271.7**	**$10.6**	**$15.8**	**$298.1**
Difference	**($29.4)**	**($1.9)**	**($1.1)**	**($32.4)**
Percent	**(11%)**	**(18%)**	**(7%)**	**(11%)**

*DR AGDE 3.122b, 3.123b and 3.124b

To adopt the Company's proposed $304.8 million test year O&M expense level for these operations (including $20.3 million of inflation) would put the spending level at $39

[16] Exhibit AG-1.34

million above what is being experienced in 2019, which would be approximately double the level of the inflation adjustment recommended by the Company. With the beginning of the projected test period approximately 6 months away, it is clear that the Company's proposed inflation adjustments for these operations are unsupported by the evidence. As such, they are unwarranted and would unreasonably increase costs for customers through higher rates if included in the determination of the Company's revenue requirement.

Therefore, I recommend that the Commission disallow the $20.3 million of inflation proposed by the Company for these three operations and all other inflation adjustments proposed by the Company in this rate case.

Q. DO YOU PROPOSE OTHER ADJUSTMENTS TO THE STEAM POWER GENERATION O&M EXPENSES?

A. Yes. I propose an adjustment of $3.1 million to Steam Generation O&M expense for the projected test year pertaining to the retirement of the St. Clair Unit #1 in March 2019. In Exhibit A-13, Schedule C5.1, the Company has included the removal of $1.4 million of expense to reflect the lower future operation and maintenance expenses after the retirement of this power generating unit. However, the adjustment proposed by the Company is not sufficient. According to my calculations, the adjustment to future O&M expense should be $4.5 million.

Q. HOW DID YOU DETERMINE THAT $4.5 MILLION IS A MORE APPROPRIATE ADJUSTMENT FOR THE RETIREMENT OF THIS FACILITY?

A. In discovery, the Company was asked to provide the calculation to support its $1.4 million adjustment, as well as the historical O&M expense for the St. Clair Unit #1. In its response, the Company stated that it does not track O&M expenses by generating unit and provided the total St. Clair plant O&M expenses for each year 2016 to 2018. This information is included in Exhibit AG-1.35.

The discovery response shows that O&M expense for the entire St. Clair plant facility decreased from $40,681,889 in 2017 to $36,425,389 in 2018. In 2017, the Company retired another generating unit, the St. Clair Unit #4, and the decline of $4.3 million in O&M expense between 2017 and 2018 can be mostly attributed to that retirement. This decline in expense provides a useful benchmark to determine what the proper amount of future decline in O&M expense should be pertaining to the Unit #1 retirement in March 2019.

Additionally, if we divide the $36,425,389 of O&M expense incurred in 2018 by the five power generating units operating that year, including Unit #1, the average expense per unit was approximately $7.3 million. This is another indication that the $1.4 million adjustment proposed by the Company is not accurate.

Furthermore, the Company's nameplate generating capacity at its St. Clair facility decreased from 1,216 MW to 1,065 MW after the retirement of Unit #1 in March 2019. This is a decrease of 151 MW, or 12.4%. As stated earlier, the O&M expense incurred at the entire St. Clair facility was $36.4 million in 2018. By multiplying this actual cost by the 12.4% MW reduction, the result is an estimated savings of $4.5 million. Exhibit AG-1.36 shows the calculations used to arrive at this amount.

This is a similar cost reduction to what was experienced between 2017 and 2018 with the retirement of the St. Clair Unit #4 and significantly less than the $7.3 million potential expense reduction if we divide the 2018 O&M expense by the five operating units. Therefore, I recommend the Commission adopt my proposed adjustment of $4.5 million and remove an additional $3.1 million from the Company's projected test year O&M expense relating to the retirement of the St, Clair Unit #1.

E. Merchant (Credit/Debit Card) Fees

Q. PLEASE ASSESS THE COMPANY'S REQUEST TO RECOVER THE INCREASED EXPENSE FOR MERCHANT FEES FROM $10.5 MILLION IN 2018 TO $19.1 MILLION IN THE PROJECTED TEST YEAR.

A. On page 1 of Exhibit A-13, Schedule C5.7.1, the Company shows the dramatic increase in Debit and Credit Card fees from $10.5 million in 2018 to a projected amount of $19.1 million for the test year. This is nearly a doubling of the expense amount in about two-and-half years. The projected increase is more dramatic for non-residential customers, where merchant fees are increasing from $4.7 million in 2018 to $10.7 million in the projected test year. The popularity of this program has grown as the Company has advertised this cost-free option to its customers.

To get these costs under control, Company witness Eric Clinton has proposed to limit eligibility for cost-free Debit/Credit card payments for non-residential customers to those customers that have less than $75,000 in annual bills. According to the Company, this restriction would reduce the amount of fees for non-residential customers by $4.7 million.

The Company did not include the $4.7 million cost savings of limiting eligibility for non-residential customers in its projected O&M expense for merchant fees. I recommend that the Company accept this restriction and remove $4.7 million of merchant fees from the projected test O&M expense.

E. Uncollectible Account Expense

Q. **WHAT ADJUSTMENT TO UNCOLLECTIBLE ACCOUNTS EXPENSE FOR THE PROJECTED TEST YEAR DO YOU RECOMMEND?**

A. I recommend an adjustment to reduce projected test year uncollectible accounts expense by $2.1 million. In response to the Commission's directive in Case No. U-20162, the Company conducted a study about the impact of debit and credit card payments on uncollectible account expense. The result of the study indicates that the use of debit/credit card payments likely reduces uncollectible account expense.

On page 13 of her direct testimony, Company witness Tamara Johnson reported that the Company conducted a study of customers in final arrears during the period September 2018 to January 2019. In response to discovery, Ms. Johnson further explained that, for the customers in final arrears with little or no credit card payment history, payments by credit card resolved $1.9 million of outstanding bills after disconnection. Exhibit AG-1.37 includes a copy of the discovery responses. This result was for the five-month study period.

As detailed and calculated in Exhibit AG-1.38, annualizing the $1.9 million amount results in a $4.6 million reduction in uncollectible expense over the full twelve-month historical period. Based on the 46% increase in credit card fees for residential customers from 2018 to the projected test year in Exhibit A-13, Schedule C5.7, the $4.6 million of annualized uncollectible expense reduction will likely increase to $6.7 million. Therefore, a reduction of uncollectible accounts expense of $2.1 million should be expected for the projected test year.

Accordingly, I recommend that the Commission reduce the uncollectible accounts expense for the projected test year by $2.1 million.

G. Fixed Bill Pilot Program

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S REQUEST TO BEGIN A FIXED BILL PILOT PROGRAM AND THE RELATED EXPENDITURES?

A. While I admire the Company's efforts to find new ways to increase customer convenience, the capital expenditures of $2.8 million and O&M expenses of nearly $1.0 million for this pilot program should not be approved by the Commission.

Company witness Eric Clinton discusses the fixed bill pilot program beginning on page 13 of his direct testimony. According to the proposal, participants would pay a fixed monthly bill, irrespective of the amount of electricity used, subject to some limitations and adjustments in subsequent periods. The Company plans to solicit 5,000 customers to participate in this program, which would commence sometime in 2020 after computer system programming is completed. Mr. Clinton points out that the Company surveyed 700 residential customers in April 2018 and that 11% indicated that they may be interested in a "Fixed Billing" offering. Mr. Clinton states that "The primary reason…was "Consistent Bill/No surprises." He does not present any other benefits or reasons for this program. The Company has included $900,000 in O&M expense in the projected test year to launch this pilot program. In addition, the Company would incur $2.8 million to undertake billing system modifications to implement the fixed billing option.

The Company's proposal in this case is basically the same pilot program proposed in Case No. U-20162. Agreeing with the objections of the AG, Staff, and other intervenors, the Commission rejected the program and recovery of costs for the program in that rate case. The facts and circumstances presented and argued in Case No. U-20162 have not changed significantly. In this rate case, the Company has filed testimony and information about similar pilots and programs in other states, but the basic fact is that only a handful of utilities in other states have pursued the fixed billing option. Most of these utilities are in the southern part of the United States.

As I stated in my direct testimony in Case No. U-20162, inasmuch as the Company already offers a budget bill program with equal payment amounts throughout the year, the new program seems duplicative and unnecessary. However, more concerning is the likelihood that the new program would discourage energy conservation. Customers may conclude that the fixed bill will avoid higher electricity bills, and may abandon energy conservation, particularly during peak demand periods. This effect would be at odds with other programs promoted by the Company to increase energy conservation, energy efficiency, and reduction of peak time usage.

The fact that the Company will adjust the fixed bill up or down the following year may not deter customers from reducing energy usage during critical peak times of the year. The Company's proposal in this rate case to notify customers that their current usage will increase their bill upon renewal in their participation in the program the following year does not resolve this concern. Instead, such warnings could create confusion and resentment on the part of the customer that the Company may not keep their end of the bargain by increasing bills in subsequent years in order to recapture what they may have lost the prior year. It may be also confusing and dangerous to communicate to customers specific bill increases or decreases for the following year due to variance in usage in the current year, when additional changes in usage and rate increases before the end of the current year may significantly affect the calculation of the customer fixed bill in the subsequent year.[17]

In his testimony in this rate case, Mr. Clinton raises the prospect that unregulated marketing companies, such as Arcadia, are offering or may be offering fixed bill options to customers. Mr. Clinton states that there are negative consequences to marketing companies offering fixed electric bills to customers because they are not regulated and are outside the oversight of the Commission. However, in the natural gas business, unregulated energy marketing companies have offered fixed prices to customers for many years, while Michigan gas utilities have not, and continue to bill customers based on actual rates and usage.

Mr. Clinton's claim that if the Company does not offer a fixed bill option, customers will be forced to go to unregulated marketing companies for energy services is a red herring. For example, Arcaida mainly markets renewable energy. Their website marketing does not even mention the fixed bill option as a major feature. Therefore, Mr. Clinton's concerns with unregulated marketing companies are overstated.

In conclusion, the Company has not made a compelling case that the underlying reasons for the pilot program are sound and in the best interest of all customers. Therefore, I

[17] Eric Clinton direct testimony at page 21.

recommend that the Commission reject the Company's request for the $900,000 of O&M expense and the capital expenditures request of $2.8 million.

G. Wellness Program

Q. WITNESS COOPER, IN HIS EXHIBIT A-13, SCHEDULE C5.11, SHOWS WELLNESS PROGRAM EXPENSES INCREASING FROM $2.2 MILLION IN 2018 TO $4.5 MILLION IN THE PROJECTED TEST YEAR. PLEASE ASSESS THE REASONABLENESS OF THIS 100% INCREASE IN WELLNESS PROGRAM EXPENSES.

A. The Company has consistently spent between $1.8 million to $2.2 million on its "wellness" program during the 2014 to 2018 timeframe. However, for the projected test year the Company proposes a doubling of the expense amount from $2.2 million in 2018 to $4.5 million for the projected test year. The direct testimony of witness Cooper, who sponsors the wellness program, is completely devoid of any explanation as to how the Company plans to spend the additional funds for the program. In discovery, the Company was asked to explain the reasons for the increased spending on the wellness program and to provide any studies the Company has conducted regarding why the additional expenditures are justified.

In response, the Company did not provide any studies performed to justify the increase in expense and instead provided two published articles supporting the concept of wellness expenditures. In discovery, the Company was asked to provide a list of other utility companies and the amount they spend on wellness programs. The Company replied that it had not compiled such information.

Given the Company's failure to support its request for higher O&M expense for the wellness program, I recommend that the Commission remove the increase in expense of $2.3 million from the Company's projected O&M expense amount for the project test year.

I. 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 April 2021, the Company seeks to recover $47.6 million of employee incentive payments. Based upon the information provided on page 49 of the revised direct testimony of Company witness Michael Cooper, $7.6 million pertains to the Annual Incentive Plan (AIP), $24.2 million to the Rewarding Employees Plan (REP), and $16.8 million pertains to the Long-Term Incentive Plan (LTIP).

2019 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 Adjusted Cash Flow and DTE Energy Earnings per Share).

2. 15% on Customer Satisfaction (Customer Satisfaction Index, Improvement in Customer Satisfaction and MPSC Customer Complaints).

3. 15% on Employee Engagement (DTE Electric Employee Engagement, DTE Electric OSHA Incident Rate, and OSHA Dart Rate and NSC Barometer Survey).

4. 30% on Operating Excellence (Distribution system reliability, Capital Investment Plan goals, Tree Trim mileage 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.

The measures described above are for the year 2019. 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.

2019 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.

2019 Long Term Incentive Plan – The LTIP for DTE Electric is an annual performance unit and stock grant plan focused on achieving multi-year goals, specifically on the following measures:

1. 60% on Common Stock Total Shareholder Return vs. a Peer Group.
2. 20% on Balance Sheet Ratio of Funds from Operations to Debt.
3. 20% on the Average Return on Equity.

The weight of these measures varies depending on whether the employee works for the utility, the parent company or the corporate service group.

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. 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 the Company and its parent, DTE Energy, achieving net income, earnings per share, and cash flow goals. Despite the argument by the Company that achieving these goals somehow benefits customers, there is no direct relationship to customer benefits. These goals are in place to maximize profits and increase cash flow to pay dividends to shareholders. It is even more inappropriate to charge customers for incentive pay costs related to achieving DTE Energy earnings, 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 2019 represents 15% of the total measures, down slightly from 20% in 2018 with regard to the AIP. The REP has been at 20% in recent years. However, as shown in Exhibit A-21, Schedule K8 Revised, the benefits achieved are far less than the costs as measured by the Company.

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. Also, as shown in Exhibit A-21, Schedule K-8 Revised, the benefits in this area fall short of the costs allocated to the incentive plans.

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 which is largely contracted out and 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 (60%) 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 two measures, the Debt coverage ratio and DTE Electric return on equity, are also very removed from any quantifiable benefits that directly accrue to customers. To some degree these last two items are actually duplicative of the Net Income and Cash Flow measures included in the AIP and REP plans.

The arguments put forth by Mr. Cooper in his revised direct 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 K8 Revised, Mr. Cooper has shown a calculation that purports to show that recent operating and financial cost savings are exceeding adjusted incentive plan payments by $51.2 million. However, the largest benefits showing in this exhibit are in the areas of (1) Financial Measures ($6.3 million); and (2) Operating Excellence ($50.3 million) with 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. It is added spending that is creating these benefits for the most part (not an employee bonus program) and the cost of such capital is not a factor in this analysis. It is also worth noting on this exhibit page that the benefits versus expenses related to the Customer Satisfaction metrics shows a net loss of $5.1 million (line 27 of the exhibit).

Q. ON PAGE 35 OF MR. COOPER'S TESTIMONY ON LINES 14 THROUGH 18, HE CHARACTERIZES THE COMPANY'S PERFORMANCE AS BEING AT 92% FOR THE AIP AND 79.9% FOR THE REP, WHICH HE INDICATES IS VERY NEAR THE TARGET LEVEL. DO YOU AGREE WITH THIS ASSESSMENT?

A. No. Exhibit A-21, Schedule K3 Revised provides a different picture, especially with respect to 2018, which is the most recent year of experience. As can be seen on lines 38 through 43 of this exhibit page, the Company performed at "less than Threshold" for 11 of the 32 metrics in 2018 and below Target on another 5 of the 32 metrics. Adding these two categories together, the Company is below the Target 50% of the time in 2018. Moreover, if one considers 2018 compared to 2017, only 7 metrics were below Target in 2017 (vs 18 in 2018)—suggesting a decline in performance levels or at least a decline in outcomes relative to management's expectations.

Q. IF CONTINUED, DO THE 2018 PERFORMANCE LEVELS REFLECT SOME UNCERTAINTY WITH RESPECT TO WHAT WILL BE PAID OUT UNDER THE INCENTIVE PLANS DURING THE PROJECTED TEST YEAR PERIOD?

A. Yes. On pages 48 and 49 of his revised direct testimony, Mr. Cooper points out that the $47.6 million of incentive compensation expense is based on “Target” performance levels. Therefore, if the Company’s sub-standard performance levels continue into the projected test period, a substantial portion of the incentive payments anticipated by Mr. Cooper will never even occur.

As reflected in Exhibit AG-1.39, the Company’s failure rate related to achieving its non-financial goals was at the 71% level in 2018 (excluding nuclear operations). Since the dollars in question here are material, this point should be recognized should the Commission determine that some incentive compensation payments should be included in customer rates in this case. To include dollars in customer rates based on target levels for the projected test year would be unreasonable should the incentive compensation payments get curtailed due to less than target performance levels

Also, as can be seen on Exhibit A-21, Schedule K3 Revised, the performance results in the 2014 to 2017 time-frame shows many metrics at either below Threshold or below Target. Accordingly, 2018 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.

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

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

A. On page 49 of his revised 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 $28.4 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 in recent cases the Commission has 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 that portion of incentive compensation expense that the Company has identified pertaining to operating performance measures, adjusted down to the level discussed below..

In the table on page 49 of Mr. Cooper's revised direct testimony, the Company shows $19.2 million of incentive compensation related to operating performance measures. However, as stated earlier, this amount assumes that 100% of the operating measures will be achieved at the target level. As discussed in my testimony above, the Company has achieved only approximately 30% of operating measures at the 100% target level or above in 2018. This fact needs to be taken into consideration in granting an appropriate amount of incentive compensation expense for operating measures. While I could recommend limiting recovery of Mr. Cooper's recommended incentive compensation for non-financial performance metrics to approximately 30% (based on 2018 performance), this seems punitive, especially since it would be dependent upon just one year of performance results. Therefore, I recommend that the Commission allow recovery of only 50% of the $19.2 million, or $9.6 million.

The Commission should deny recovery of the remainder of the $47.6 million in incentive compensation expense proposed by the Company and thus disallow the amount of $38.0 million.

Q. IS THERE A PORTION OF INCENTIVE COMPENSATION THAT THE COMPANY INCLUDES IN CAPITAL ADDITIONS AND RATE BASE, WHICH IS NOT INCLUDED IN THE CHART ON PAGE 49 OF MR. COOPER'S REVISED DIRECT TESTIMONY?

A. Yes. The chart on page 49 of Mr. Cooper's revised direct testimony only includes the projected incentive compensation pertaining to O&M expense for the projected test year. In addition, each year the Company allocates and capitalizes a portion of both short-term and long-term incentive compensation, which is included in rate base. In response to discovery, the Company provided information on the amount of incentive compensation capitalized for 2018 through 2021. Exhibit AG-1.40 includes the information provided in response to discovery.

The amounts pertaining to 2018 through the end of the projected test year are $25.2 million for short-term compensation and $19.2 million for long-term compensation. These amounts reflect the Commission's prior decisions to allow recovery of only incentive compensation pertaining to operating performance measures for the short-term incentive plans and no recovery for long-term incentive compensation. Exhibits AG-1.11 ad AG-1.40 show the amounts prorated and pertaining to each forecasted period. I recommend that the Commission remove these amounts from projected rate base. In addition, I recommend that the Commission direct the Company to identify in future rate cases the amount of capitalized incentive compensation included in projected rate base for the projected periods in the same detail as provided in the chart on page 49 of Mr. Cooper's revised direct testimony. Furthermore, the Company should affirm in filed testimony that it has removed from historical rate base all incentive compensation previously disallowed by the Commission. This information will facilitate the analysis of allowable incentive compensation included in rates and will ensure its accuracy.

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 $128.8 million as discussed above and summarized in the following table. Exhibit AG-1.41 provides additional details of the areas where I have proposed O&M expense adjustments.

Summary of O&M Expense Reductions	Amount ($Millions)
Inflation Expense Adjustment	$ 69.8
Power Generation	3.1
Distribution Operations	7.9
Credit/Debit Card Fees	4.7
Uncollectible Accounts Expense	2.1
Employee Incentive Compensation	38.0
Employee Benefits & Other	3.2
Total Reduction	**$ 128.8**

IX. Depreciation Expense

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

A. Yes. As a result of the reductions in capital expenditures proposed above in my testimony and the impact on capital additions included in rate base, I have calculated a reduction in depreciation expense of $16,987,000. The calculation of this amount is shown in Exhibit AG-1.11 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 $16,987,000.

X. Excess Deferred Taxes

Q. AS A RESULT OF VARIOUS COMMISSION ORDERS ISSUED ON THE CALCULATION AND PASSTHROUGH TO CUSTOMERS OF EXCESS DEFERRED TAXES, EMANATING FROM THE FEDERAL TAX CUTS AND JOBS ACT OF 2017(TCJA), ARE THERE ISSUES THAT THE COMMISSION HAS NOT YET ADDRESSED WITH REGARD TO DTE ELECTRIC?

A. Yes. DTEE was one of a few utilities under the jurisdiction of the Commission that did not file a separate case for the determination of Calculation C issues and the passthrough of excess accumulated deferred federal income taxes (ADFIT) to customers. Instead, only some issues, such as the inclusion of the amortization of the excess ADFIT were addressed in Case No. U-20162 and in this rate case. However, unlike the Calculation C cases for other utilities, the Commission has not addressed the procedures for reconciliation and reporting of the excess ADFIT over future years.

Q. SHOULD THE COMPANY BE REQUIRED TO RECONCILE THE ACTUAL AMOUNT OF EXCESS DEFERRED TAX AMORTIZATION TO THE THE AMOUNT ESTIMATED IN SETTING BASE RATES AND REPORT TO THE COMMISSION THOSE DIFFERENCES?

A. Yes. The annual amortization amount of the excess deferred taxes for the protected property portion is not a fixed straight-line annual amortization. The amortization amount changes from year to year as the timing differences of the underlying depreciable assets vary. It is also likely that retirements and other adjustments to plant and non-plant assets and liabilities will change the annual amortization of both protected and non-protected excess deferred assets and liabilities.

Therefore, the net excess deferred tax amortization amounts assumed in base rates will not likely match the actual annual amortization amounts. To ensure that customers receive the actual excess deferred tax savings owed to them, I recommend that the Commission order the Company to establish a regulatory deferred asset or liability account to record the annual differences between the excess deferred taxes passed through to customers versus the actual amortization amounts for each of the three categories of excess deferred taxes. The differences in the regulatory liability or asset account will be reflected in customer rates over a period of time established by the Commission in the Company's next general rate case. The Commission should order the Company to begin this reconciliation with the first year's amortization of the excess ADFIT.

In addition, the Commission should direct the Company to file an annual letter to this case docket by March 31 of each year until the excess deferred taxes are completely refunded to customers. For each of the three categories of excess deferred taxes, the letter should include: (1) the beginning refundable balance, (2) the yearly amount passthrough to customer, (3) the over/under regulatory asset/liability the Company has recorded, which is calculated as the difference between the actual amount of excess deferred taxes in a given year and the estimated amount included in rates, and (4) the ending refundable balance.

Q. WHEN FILING A RATE CASE, AND FOR RATEMAKING PURPOSES, WHERE SHOULD THE EXCESS DEFERRED TAXES NOT YET REFUNDED TO CUSTOMERS BE INCLUDED?

A. Deferred taxes are considered zero cost capital and are normally included in the capital structure as a source of capital in the calculation of the overall cost of capital. Before the enactment of the TCJA, all deferred taxes at the federal tax rate of 35%, as well as comparable state deferred taxes, were included in the capital structure. Although a portion of the deferred taxes representing the difference in the federal tax rate from 35% to 21% are now refundable to customers, these amounts are still deferred taxes that have not yet been refunded and they properly belong with other deferred taxes in the capital structure at zero cost.

Therefore, I recommend that the remaining excess deferred tax liabilities and assets for the projected test year that are not yet passed through to customers be included with other deferred income taxes in the capital structure in future general rate cases. From DTEE's filing in this rate case, the Company has taken this same approach. However, the Commission order in this rate case should clearly specify that requirement.

XI. Adjustments To Revenue Deficiency

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

A. Exhibit AG-1.42 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $41.1 million, which is a reduction of $309.6 million from the Company's requested level of $350.7 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $41.1 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 more than 15 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).

During his 24-year career at MCN and MichCon, he held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many of

Experience and Qualifications
of Sebastian Coppola

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.

ENERGY INDUSTRY EXPERIENCE

Mr. Coppola has been an independent consultant for more than 15 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 gas utility operations and non-regulated businesses. 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.

During his 24-year career at MCN and MichCon, he held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

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

ENERGY INDUSTRY 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 and other regulatory proceedings. 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.

Experience and Qualifications of Sebastian Coppola

Mr. Coppola has extensive experience with gas utilities in the areas of gas operations, gas supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General 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 and Wisconsin Public Service Company.

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

As manager of customer billing, Mr. Coppola developed intricate knowledge of customer billing and meter reading operations. As manager of materials inventory and warehousing accounting, he also developed intricate knowledge of pipeline and materials procurement, warehousing and construction operations including safety compliance issues. Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

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

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

- **Specific Regulatory Proceedings And Related Experience:**
  - 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 Energy Gas Company (SEMCO) 2019 gas rate Case U-

Experience and Qualifications of Sebastian Coppola

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 Consumers Energy Company (CECo) 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (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 Michigan Indiana Power Company (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.

Experience and Qualifications of Sebastian Coppola

- 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 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 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.
- 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.

Experience and Qualifications
of Sebastian Coppola

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

Experience and Qualifications of Sebastian Coppola

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

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CECo Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main

Experience and Qualifications
of Sebastian Coppola

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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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 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.

Experience and Qualifications
of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications
of Sebastian Coppola

- 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.
- 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.

**Experience and Qualifications
of Sebastian Coppola**

- 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.

Experience and Qualifications
of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

Experience and Qualifications
of Sebastian Coppola

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.

PROOF OF SERVICE - U-20561

The undersigned certifies that a copy of the **Attorney General's Direct Testimony & Exhibits of Sebastian Coppola,** was served upon the parties listed below by e-mailing the same to them at their respective email addresses on the 6th of November 2019.

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