STATE OF MICHIGAN
DEPARTMENT OF ATTORNEY GENERAL

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June 24, 2020

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

Dear Ms. Felice:

Re: MPSC Case No. U-20697

Attached for filing is the public version of the ***Direct Testimony and Exhibits of Sebastian Coppola on behalf of Attorney General Dana Nessel***. A proof of service is also attached.

Sincerely,

Celeste R. Gill
Digitally signed by Celeste R. Gill
Date: 2020.06.24 14:03:39 -04'00'

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PROOF OF SERVICE - U-20697

The undersigned certifies that a copy of the ***Direct Testimony and Exhibits of Sebastian Coppola on behalf of Attorney General Dana Nessel*** was served upon the parties listed below by emailing the same to them at their respective e-mail addresses on the 24th day of June 2020.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-20697

In the matter of the application of	)
CONSUMERS ENERGY COMPANY	)
for authority to increase its rates for	)
the generation and distribution of	)
electricity and other relief	)

PUBLIC

Direct Testimony

And Exhibits

of

Sebastian Coppola

On behalf of

Attorney General Dana Nessel

June 24, 2020

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I. Introduction

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

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

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than 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. 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, capital expenditures, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, I have performed analysis of power costs and filed testimony in power supply cost recovery cases, including reconciliation of annual power supply costs.

In my position as Senior Vice President of Finance at MCN, I also 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 in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 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 CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in 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.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Michigan Department of Attorney General to perform an independent analysis of Consumers Energy Company's ("CECo" or the "Company") Electric Rate Case filing in Case No. U-20697. This testimony presents a report of that analysis with related recommendations.

Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?

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

1. The level of proposed rate base and capital expenditures
2. The Company's proposed deferred recovery mechanism for excess capital expenditures.
3. The Company's cost of capital
4. The level of operations and maintenance expenses
5. Various Cost Recovery and Cost Deferral Proposals

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 CECo'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 DR Response – HVD Lines New Business
2. Exhibit AG-1.2 DR Response – Demand Failures-Service restoration
3. Exhibit AG-1.3 Demand Failures Calculation of Cap Ex Reductions

4. Exhibit AG-1.4 DR Response – Center Suspended Streetlights
5. Exhibit AG-1.5 DR Response – Metro Cap Ex Forecast Revised
6. Exhibit AG-1.6 DR Response – HVD Lines Rehab
7. Exhibit AG-1.7 HVD Lines Rehab Calculation of Cap Ex Reductions
8. Exhibit AG-1.8 DR Response – LVD Substation Rehab
9. Exhibit AG-1.9 LVD Station Rehab Calculation of Cap Ex Reductions
10. Exhibit AG-1.10 DR Response –Grid Automation
11. Exhibit AG-1.11 Grid Automation Calculation of Cap Ex Reductions
12. Exhibit AG-1.12 DR Response – LVD Substation Rehab.
13. Exhibit AG-1.13 DR Response – LVD Lines Rehab
14. Exhibit AG-1.14 LVD Lines Rehab Calculation of Cap Ex Reductions
15. Exhibit AG-1.15 DR Response – HVD Line & Substation Capacity
16. Exhibit AG-1.16 DR Response – HVD lines Interconnections.
17. Exhibit AG-1.17 DR Response – Truck and Other Capital Tools
18. Exhibit AG-1.18 Truck and Other Tools Calculation of Cap Ex Reductions
19. Exhibit AG-1.19 DR Response – HVD System Controls
20. Exhibit AG-1.20 HVD System Controls Calculation of Cap Ex Reductions
21. Exhibit AG-1.21 DR Response Conceptual Projects
22. Exhibit AG-1.22 CONFIDENTIAL – 27 Conceptual Projects in WP-RTB-5
23. Exhibit AG-1.23 DR Response – Dry Ash Cell Landfill project
24. Exhibit AG-1.24 DR Response – Karn 1 and 2 Decommissioning Costs
25. Exhibit AG-1.25 CONFIDENTIAL DR Response – Jackson Warehouse project
26. Exhibit AG-1.26 DR Response – Hardy Spillway Remediation
27. Exhibit AG-1.27 DR Response – Ludington Unit 3 Upgrade/Overhaul
28. Exhibit AG-1.28 DR Response – Ludington Reservoir Liner.
29. Exhibit AG-1.29 DR Response – 2019 Actual Cap Ex
30. Exhibit AG-1.30 DR Response – Grid Storage
31. Exhibit AG-1.31 DR Response – Service Centers Information
32. Exhibit AG-1.32 DR Response – Circuit 501 Training Center
33. Exhibit AG-1.33 DR Response – UCC project

34. Exhibit AG-1.34 Transportation Fleet Information and DR Responses
35. Exhibit AG-1.35 DR Response – Fleet O&M Costs
36. Exhibit AG-1.36 DR Response – Telematics Selection and Cost Savings
37. Exhibit AG-1.37 DR Response – IT Dashboard and Website Redesign
38. Exhibit AG-1.38 DR Response – IT Work Scheduling, Service Tracker, etc.
39. Exhibit AG-1.39 DR Response – IT Bill Design, MIMO, On Bill Financing
40. Exhibit AG-1.40 DR Response – Actual 2019 Capital Expenditures
41. Exhibit AG-1.41 DR Response – Demand Response Program
42. Exhibit AG-1.42 Summary Cap Ex, Rate Base and Depreciation Expense
43. Exhibit AG-1.43 Overall Cost of Capital
44. Exhibit AG-1.44 Calculation of Impact of TCJA on Cash Coverage Ratios
45. Exhibit AG-1.45 Cost of Common Equity
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62. Exhibit AG-1.62 Service Outage Incidents
63. Exhibit AG-1.63 DR Response - Training and New Hires

64. Exhibit AG-1.64 DR Response – Uncollectible Information 2019
65. Exhibit AG-1.65 DR Response – Injuries and Damages Costs 2019
66. Exhibit AG-1.66 DRE Response - CPI Data April 2020
67. Exhibit AG-1.67 DR- Response – IT Investment O&M Expense
68. Exhibit AG-1.68 DR Response – Incentive Compensation at Threshold Level
69. Exhibit AG-1.69 Service Restoration cost in O&M and Capitalized
70. Exhibit AG-1.70 CVR Savings Determination Process
71. Exhibit AG-1.71 AG Revenue Deficiency Calculation

II. SUMMARY CONCLUSIONS & RECOMMENDATIONS

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

A. The Company filed for a jurisdictional rate increase of $244.3 million. The rate increase represents an overall increase in base rates of 5.9% and an increase of 14% to residential base rates. It is noteworthy to point out that in the 2018 historical test year, the Company had a revenue sufficiency of $21.8 million.[1] In response to discovery, the Company reported that for 2019, it again had a revenue sufficiency of $20.6 million.[2]

Furthermore, during the past five years from 2015 to 2019 the Company earned a return on equity (ROE) on a regulatory basis significantly higher than the allowed ROE during the same period.[3]

[1] Exhibit A-1 (HJM-1), Schedule A1.
[2] CECo response to discovery request AG-CE-1302.
[3] Exhibit A-1 (HJM-2), Schedule A2, page 4, and response to DR AG-CE-1302.

In approving cost recovery and establishing fair and reasonable rates in this rate case, the Commission should be mindful of the fact that the Company's cost projections have resulted in an extended period of excess earnings and returns on equity capital well above authorized levels.

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 $20.7 million.[4] My conclusions and related adjustments are summarized below:

1. I recommend a reduction in capital expenditures of $415 million and a reduction of $253.4 million to rate base for the test year. This reduces the Company's revenue deficiency by $18.7 million.

2. I recommend that the Commission adopt a lower cost of capital rate of 5.50%, a capital structure with 50% equity capital and a return on common equity of 9.50%. These recommendations reduce the Company's revenue deficiency by $94.0 million.

3. I recommend a lower level of Operations and Maintenance expenses for the test year. This reduces the Company's revenue deficiency by $99.0 million.

[4] This determination is based on my evaluation of the Company's filed positions and should not be interpreted as determination of the merits of the proposals or recommendations of other witnesses providing testimony on behalf of the Attorney General.

4. I recommend a lower amount of depreciation expense of $12.4 million pertaining to the lower capital expenditures and additions to plant discussed above. This adjustment reduces revenue deficiency by $12.4 million.

5. I recommend that the Commission order the Company to complete a reassessment of the benefits of the Demand Response program due to the significant increase in costs and decrease in generating capacity reductions.

6. I recommend that the Commission reject the Company's proposal to establish a Capital Spending Deferral and Recovery mechanism.

7. I recommend that the Commission reject the Company's proposed Service Restoration Cost Deferral and Recovery mechanism.

8. I recommend that the Commission reject the proposed deferral and amortization of employee retention and severance costs for the Karn 1 and 2 decommissioning.

9. I recommend that the Commission reject the proposed Conservation Voltage Reduction Cost Savings Sharing mechanism.

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

III. CAPITAL EXPENDITURES AND RATE BASE

Q. WHAT ARE YOUR FINDINGS IN ANALYZING THE COMPANY'S PROPOSED LEVEL OF CAPITAL EXPENDITURES ADDED TO RATE BASE?

A. The Company is continuing a major ramp up of capital expenditures in a variety of areas. In this rate case filing, $181 million, or 74%, of the requested rate increase of $244 million is for higher rate base related to capital expenditures. The compounding effect of large additions to rate base will continue to increase customer rates to a level that is unaffordable for many customers, particularly those in lower income brackets. This trend is not sustainable for customers.

CECo has proposed capital expenditures of $926.3 million for 2019, $803.6 million for 2020, and an additional $1.098 billion for 2021. These increases are in addition to capital expenditures of $1.6 billion made during the prior two years in 2017 and 2018.[5]

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 area and I have identified more reasonable and prudent expenditure levels that the Commission should consider. In my analysis, I will often use the most recent three years of actual costs and unit costs, where applicable, to determine the reasonableness of the Company's forecasted costs. This approach normalizes various costs from year to year and reflects the most recent costs actually experienced by the Company during a period of very low inflation.

In discovery, the Company was asked to provide the inflationary increases built into its forecasts for O&M and capital expenditures. The Company provided information on labor

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[5] Exhibit A-12, Schedule B-5 in MPSC Case No. U-20697 and U-20134.

and non-labor inflation increases for O&M expense, but no information on inflation adjustments for capital spending.[6] As a result of that finding, the low inflation likely to be experienced in 2020 and 2021 due the current economic recession, and my approach of using recent historical data, I decided not to apply inflation cost increases when projecting capital expenditures for 2020 and 2021.

A. Contingent Capital Expenditures

The Company has disclosed that it included total contingency costs of $17,928,000 in its forecasted capital expenditures in the power generation area for 2020 and 2021. Page 4 of Exhibit A-12, Schedule B-5.2 shows this information. The Company did not report any additional contingency costs from other operations.

The $17,928,000 should be excluded from the calculation of rate base for the projected test year. Contingency expenditures are typically the amounts above the base forecast of capital expenditures for non-routine projects. The contingency amounts are usually established early in the life cycle of the project in case increases in costs are experienced due to unforeseen circumstances. The fact that these added costs are contingent means that they may not be spent, either in whole or in part. Despite the Company's claim in prior rate cases that the amounts may actually be spent on the project or may be spent on other new work, these costs do not belong in rate base. It is neither fair nor reasonable for the Company to recover the depreciation expense and the return on the investment on

[6] CECo response to discovery request AG-CE-602.

potential costs that may not actually be incurred but have nonetheless been added to rate base.

Although the Company may argue that including contingency costs in the forecasted cost of a project is an accepted project management practice, it does not mean that these costs belong in rate base. There should be a higher degree of scrutiny and acceptance of costs that are included in rates in the ratemaking process versus budgeting conventions. The Commission should take a reasonable approach and disallow the contingent capital costs to prevent the Company from recovering in rates billed to customers the return of and the return on costs that are very tentative and contingent. If the Company actually incurs those costs, they can be included in rate base in the next rate case.

In the Company's prior rate cases, Case Nos. U-17735, U-17990, U-18124, and U-20322, 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-18014, U-17999, U-17767, U-20162, and U-20561. Nothing has changed since the Commission made these determinations. Therefore, I recommend that the Commission exclude the $17,928,000 from the forecasted capital expenditures in this rate case filing.

B. Electric Distribution Capital Expenditures

As shown in Exhibit A-12 (RTB-1), Schedule B-5.1, the Company incurred capital expenditures of $533.2 million for the Electric Distribution plant in 2018, and forecasted $628.9 million for 2019, $552.1 million for 2020, and $722.7 million for 2021. Included in these total amounts are capital expenditures for New Business, Reliability programs, Capacity expansions, Demand Failures upgrades, Asset Relocation projects and Electric Operations Other. I evaluate and propose adjustments to several of these programs and component projects below.

In his testimony and some of his accompanying exhibits, Company witness Richard Blumenstock presents forecasted capital expenditures in two major categories in line with the design of its distribution system, consisting of High Voltage Distribution (HVD) and Low Voltage Distribution (LVD) facilities.

Q. DO YOU HAVE ANY OBSERVATIONS ABOUT THE SYSTEM RELIABILITY GOALS AND THE DISTRIBUTION INFRASTRUCTURE INVESTMENT PLAN DISCUSSED IN MR. BLUMENSTOCK'S TESTIMONY?

A. Yes. The Company has set a goal to achieve a SAIDI goal of 187 minutes by the year 2022 and reduce it further to 170 minutes by 2025. SAIDI, which is an acronym for System Average Interruption Duration Index, measures both the frequency and average time that electric service to customers is interrupted during the year. The index is measured both including and also excluding major event days. Major event days (MEDs) reflect major storms days. The SAIDI, excluding MEDs, is more commonly used as a normalized index to major system reliability performance over time.

As shown on page 27 of Mr. Blumenstock's direct testimony, the Index has been up and down during the past 10 years reaching a high point of 305 minutes in 2013 and a low point of 161 minutes in 2017. When it appears in certain years that performance has improved, the index often reverses. For example, the index has been increasing in the last two years from the low level of 2017. The Company usually attributes the escalation to tree damage and deteriorating electric infrastructure.

In Case No. U-20134 and in its Electric Distribution Infrastructure Investment Plan ("EDIIP") filed with the Commission in 2018, the Company had forecasted that it would reach a SAIDI score of 170 minutes in 2022. In his direct testimony in this current case, Mr. Blumenstock now admits that the 170-minute goal was erroneous and cannot be achieved until 2025. Mr. Blumenstock also states that in order to achieve that goal, the Company will need to spend higher amounts on capital Reliability subprograms than previously forecasted in the 2018 EDIIP.[7]

The EDIIP forecasts in excess of $3 billion of capital expenditures plus $973 million of O&M costs over the five-year period from 2018 to 2022.[8] The capital programs included in the EDIIP not only include expenditures which have a direct impact on system

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[7] Richard Blumenstock direct testimony at page 13.
[8] MPSC Case No. U-20134, Exhibit AG-2.

performance, such as Reliability and Demand Failures programs, which would replace aging infrastructure, but also capital expenditures for New Business, Asset Relocation and Capacity expansion projects. In fact, the Reliability and Demand Failure programs account for only 58% of the $3 billion in capital spending over the five-year period.

It is worth pointing out that capital expenditures for Demand Failures remain relatively flat over the five-year period. On the other hand, Reliability expenditures increase from $111 million in 2017 to a high of $232 million during the projected 2018-2022 period. On average over the five-year period, the Company projected spending close to $200 million annually on system reliability projects. In the current rate case, the Company increased the amount forecasted for the 2021 projected test year to more than $331 million. This is a 200% increase in capital expenditures from the level in 2017.

However, this increase in capital expenditures does not match the decline in the SAIDI. Achieving a SAIDI of 170 minutes in 2025 is not an improvement over the 161 minutes reported in 2017.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION?

A. It is apparent from the SAIDI results that the increase in capital expenditures for Reliability programs and other increases in spending, such as tree trimming, have not had a beneficial effect on system reliability so far. If the Commission approves a higher level of spending in many of the programs proposed by the Company, the approval should come with conditions and accountability for results. If the Company does not achieve those results, then it should forfeit recovery of a portion of the amounts spent. I will provide more details and recommendations in this regard later in my testimony.

Q. DO YOU HAVE ANY OBSERVATIONS ABOUT THE WIND DATA PRESENTED BY MR. BLUMENSTOCK IN HIS TESTIMONY?

A. Yes. Beginning on page 21 of his direct testimony, Mr. Blumenstock posits that wind conditions have intensified in recent years and have exposed the severity of the Company's deteriorating electrical system. There are two basic problems with his argument. First, looking carefully at the wind information shown in Figure 6 and other graphs shown on pages 22 to 25 of his testimony, it is readily apparent that 2017 and 2019 were two unusual years in a span of 10 years. There is no obvious trend in recent years that wind speeds are consistently higher than prior years. In fact, 2018 had the second lowest wind speeds in the entire decade. The dramatic graph on page 25 simply shows that with higher wind speeds there are more power interruption incidents. This should be expected when winds reach high levels of speed. However, the graph does not prove that the Company's system has achieved a tipping point in its gradual deterioration due to age.

Second, Mr. Blumenstock presents no evidence of a major change in the rate of deterioration of the electrical system under either normal conditions or periods of high wind. As stated earlier, the information presented to show that more failure incidents occur under high wind conditions is not evidence of a higher rate of deterioration of the system that must be addressed with further increases in capital spending.

Therefore, the Commission should not give any weight to the wind information presented in Mr. Blumenstock's testimony.

1. HVD Lines – New Business Strategic Customers

On line 3 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $12,114,000 for the year 2020 and $17,281,000 for 2021 to build new HVD lines for large strategic customers. In discovery, the Company was asked to provide the detailed components of the forecasted spending. In the detail listing provided with discovery response AG-CE-962, which is included in Exhibit AG-1.1, the Company shows $2,999,000 of expenditures for 2020 and $1,891,000 for 2021 as "Additional projects to be identified." This amount appears to be a placeholder amount for unspecified projects that have not been identified as of the date of the filing. It is uncertain whether this amount will be spent and on which specific projects. As such, it is not appropriate to allow such a speculative amount to be included in rate base on which the Company will earn a return and recover depreciation expense. The Commission has made it clear in prior rate cases that placeholder amounts would not be included in rate base.

Therefore, I recommend that the amounts of $2,999,000 for 2020 and $1,891,000 for 2021 be excluded from the Company's forecasted capital expenditures in this rate case.

2. LVD Lines Demand Failures

On line 35 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $67,960,000 for the year 2020 and $78,538,000 for 2021 to address LVD line failures. In discovery, the Company was asked to provide the detailed components of the forecasted spending. In the detail schedule provided with discovery response AG-CE-969, which is included in Exhibit AG-1.2, the Company shows two components: Service Restoration Orders and Streetlight Failures. In addition to the historical and forecasted amounts for each component, the Company also provided the number of units completed and forecasted to be completed for 2014 to 2021.

In Exhibit AG-1.3, I calculated the average cost per unit for the three historical years 2017 to 2019 at $2,792,000 per Service Restoration Order and $537,000 per Streetlight Failure. By applying the average historical unit cost to the forecasted units, I have determined that the Company's forecasted costs for Service Restoration Orders for 2020 and 2021 are excessive. My calculations show that the forecast for 2020 should be $49,823,000 and for 2021 it should be $56,245,000. Instead, the Company forecasted $55,320,000 and $63,045,000 for 2020 and 2021, respectively.

The Company did not provide any explanation or justification in testimony or in discovery responses to support the significant increase in forecasted unit costs. Therefore, I recommend that the Commission remove the excess amounts of $5,497,000 for 2020 and $6,800,000 for 2021 from this rate case.

Similarly, for the Streetlight Failures, my calculations show that the forecast for 2020 should be $8,631,000 and for 2021 it should be $10,789,000. Instead, the Company has forecasted $12,640,000 and $15,493,000 for 2020 and 2021, respectively.

The Company did not provide any explanation or justification in testimony or in discovery responses to support the significant increase in forecasted unit costs. Therefore, I recommend that the Commission remove the excess amounts of $4,009,000 for 2020 and $4,914,000 for 2021 from this rate case.

I recommend a total disallowance of $9,506,000 for 2020 and $11,717,000 for 2021 in capital expenditures for this program.

3. Demand Failures- Streetlight Center Suspended

On line 41 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $5.000,000 for the year 2021 to replace streetlights center-suspended across the road. On page 91 of his testimony, Mr. Blumenstock estimates that the Company has 11,000 such streetlight installations and some fail from time to time. According to the Company, when they fail it requires diverting traffic temporarily, which Mr. Blumenstock believes presents safety issues. The Company is proposing to replace these streetlights by 2029 with a pole on the side of the road and a bracketed arm with the light over the road. The Company wants to begin this new program by replacing 667 streetlights in 2021.

In discovery, the Company was asked to provide the number of streetlights that have been replaced each year from 2014 to 2019. In discovery response AG-CE-975, which is included in Exhibit AG-1.4, the Company shows that no replacements, and apparently no failures, occurred between 2014 and 2017. In 2018, the Company replaced 8 streetlights and in 2019 it replaced 42 lights. The Company was also asked to explain why it is necessary to accelerate replacement of the streetlights if they are still working. In its response the Company stated that replacement of the streetlight is a complex procedure done best outside of a failure to avoid an extended outage and safety issues.

From the evidence provided, it is apparent that the number of failures historically has been small. This is a program that should not be a priority during a period of time when the Company has greater needs in other areas with failing infrastructure and reliability problems.

The Company repaired 42 streetlights in 2019. Assuming that number continues into the projected test year, the capital expenditures would be $315,000 at cost per light of $7,500. I recommend that the Commission disallow the proposed capital expenditures of $4,685,000 for 2021 from this rate case.

4. Metro Failures

On line 42 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $3.000,000 for the year 2020 and $3,100,000 for 2021 to replace failed electric cable, transformers and other infrastructure in Metro areas. In response to a discovery request, the Company stated that after filing this rate case, it decided to reduce the capital expenditures for this program to $1,000,000 for 2020. See Exhibit AG-1.5.

Therefore, I recommend that the Commission remove the $2.0 million that will not be spent on this program from the 2020 capital expenditures.

5. HVD Lines Reliability

On line 9 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $78,129,000 for 2021 to address HVD line reliability problems. In discovery, the Company was asked to provide the detailed components of the forecasted spending. In the detail schedule provided with discovery response AG-CE-984, which is included in Exhibit AG-1.6, the Company shows four components for 2021: Line Rebuilds, Pole Top Rehabilitation, Pole Replacement and Switches. In addition to the historical and forecasted amounts for each component, the Company also provided the number of units completed and forecasted to be completed for each year 2014 to 2021.

In Exhibit AG-1.7, I calculated the average cost per unit for the three historical years 2017 to 2019 at $421,000 per Line Rebuild, $75,973 per Pole Top Rehabilitation and $18,235 per Pole Replacement. By applying that average historical unit cost to the forecasted units, I have determined that the Company's forecasted costs for Line Rebuilds for 2021 is overstated. My calculations show that the forecast for 2021 should be $30,312,000. Instead, the Company has forecasted $46,406,000. The difference is $16,094,000.

Similarly, for Pole Top Rehabilitations, my calculations show that the forecast for 2021 should be $8,053,000. Instead, the Company has forecasted $9,658,000. The difference is $1,605,000.

For Pole Replacements, I calculated a forecasted cost of $16,229,000. The Company forecasted a cost of $17,614,000. The difference is $1,385,000.

The Company did not provide any explanation or justification in testimony and in discovery responses to support the significant increase in forecasted unit costs. Therefore, I recommend that the Commission remove the excess 2021 capital expenditure amounts from this rate case, which total to $19,084,000.

6. LVD Substation Reliability

On line 10 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $11,500,000 for the year 2020 and $15,502,000 for 2021 to address LVD substation reliability problems. In discovery, the Company was asked to provide the detail components of the forecasted spending. In the detail schedule provided with discovery response AG-CE-986, which is included in Exhibit AG-1.8, the Company shows six components. I will address two of the six components, the Mobile Substations and the Animal Mitigations program, where significant cost differences exist. In addition to the historical and forecasted amounts for each component, the Company also provided the number of units completed and forecasted to be completed from 2014 to 2021.

In Exhibit AG-1.9, I calculated the average cost per unit for the four historical years 2015, 2016, 2018 and 2019 for Mobile Substations. I excluded 2017 because only a small amount of spent in that year for Mobile Substations. The average cost per Mobile Substation during the historical four-year period was $1,260,000. By applying that average historical unit cost to the forecasted units, I have determined that the Company's forecasted costs for Mobile Substations for 2020 and 2021 are excessive. My calculations show that the forecast for 2020 should be $5,040,000 for four units, and for 2021 it should be $1,260,000 for one unit. Instead, the Company has forecasted $6,300,000 and $3,360,000 for 2020 and 2021, respectively.

The Company did not provide any explanation or justification in testimony and in discovery responses to support the significant increase in forecasted unit costs. Therefore, I recommend that the Commission remove the excess amounts of $1,260,000 for 2020 and $2,100,000 for 2021 from this rate case.

Similarly, for the Animal Mitigation program, my calculations show that during the 3-year period from 2017 to 2019, the average cost per project was $45,174. By applying that average historical unit cost to the forecasted units, I have determined that the Company's forecasted costs for the Animal Mitigation program for 2020 and 2021 are overstated by $996,000 and $2,195,000, respectively. My calculations show that the forecast for 2020 should be $904,000 for 20 projects, and for 2021 it should be $1,807,000 for 40 projects. Instead, the Company has forecasted $1,900,000 and $4,002,000 for 2020 and 2021, respectively.

The Company did not provide any explanation or justification in testimony and in discovery responses to support the significant increase in forecasted unit costs. Therefore, I recommend that the Commission remove the excess amounts of $996,000 for 2020 and $2,195,000 for 2021 from this rate case.

In total, for this program, I recommend the disallowance of capital expenditures $2,256,000 for 2020 and $4,295,000 for 2021.

7. Grid Modernization

On lines 16, 17 and 54 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $11,500,000 for the year 2020 and $69,604,000 for 2021 to install automated line sensors, regulators and other potential technology devices. In discovery, the Company was asked to provide the detail components of the forecasted spending. In the detail schedule provided with discovery response AG-CE-989, which is included in Exhibit AG-1.10, the Company shows eight components. I will address three of the eight components, the Line Sensors, the Regulator Controllers, and the Grid Technologies program, where significant cost differences exist. In addition to the historical and forecasted amounts for each component, the Company also provided the number of units completed and forecasted to be completed from 2014 to 2021, where applicable.

In Exhibit AG-1.11, I calculated the average cost per unit for the three historical years 2017 to 2019 for Line Sensors. The average cost per Line Sensor is $4,880. By applying that average historical unit cost to the forecasted units, I have determined that the Company's forecasted costs for Line Sensor for 2021 is excessive. My calculations show that the forecast for 2021 should be $488,000 for 100 units. Instead, the Company has forecasted $4,544,000 in capital expenditures for 2021. The difference is $4,066,000.

The Company did not provide any explanation or justification in testimony and in discovery responses to support the significant increase in forecasted unit costs. Therefore, I recommend that the Commission remove the excess amounts of $4,066,000 for 2021 from this rate case.

Similarly, for the Regulator Controllers program, my calculations show that for the 3-year period from 2017 to 2019, the average cost per unit was $35,083. By applying that average historical unit cost to the forecasted units, I have determined that the Company's forecasted costs for the Regulator Controller program for 2020 are overstated by $5,213,000. My calculations show that the forecast for 2020 should be $7,367,000 based on 210 projects. Instead, the Company has forecasted $12,580,000.

The Company did not provide any explanation or justification in testimony and in discovery responses to support the significant increase in forecasted unit costs. Therefore, I recommend that the Commission remove the excess amounts of $5,213,000 for 2020 from this rate case.

With regard to the Grid Technologies project, the Company has proposed to spend $1,350,000 during 2021 to launch a project to capture photographs of system assets and store them in the GIS data base. The Company states that there are benefits from capturing these images when making certain assessments about the state of the assets and for field personnel to review the images before arriving at the job site. It is not clear how advantageous and cost effective this project would be. The Company did not provide enough support and analysis to adequately justify spending $1,350,000 on this project at a time when there are more pressing priorities. I recommend that the Commission disallow the inclusion of the capital expenditures for this project from this rate case.

In total, for this category of capital programs, I recommend the disallowance of capital expenditures of $5,213,000 for 2020 and $5,406,000 for 2021.

8. HVD Lines and Substations Rehabilitation

On line 18 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $14,222,000 for 2020 and $38,921,000 for the year 2021 to rehabilitate and replace HVD lines, substations, and related equipment. In response to discovery request AG-CE-995, the Company provided a detailed schedule showing the historical and projected capital expenditures and work units from 2014 to 2021. The five components that make up this budget category are: Pole Replacements, Pole Top Assembly replacements, Switch Replacements, Other replacements, and HVD Substation Failure projects.

In my analysis, I determined that the forecasted amounts for 2020 and 2021 for four of the five items are within a reasonable range based on the historical expenditures relative to the units completed in prior years and forecasted to be completed in 2020 and 2021. However, with regard to the HVD Substation failure program, the Company has forecasted a significant increase in capital expenditures from approximately $8.3 million in 2019 and $5.3 million in 2020 to $28.9 million in 2021.

On page 176 of his testimony, Mr. Blumenstock has identified four projects that total to $24.0 million. This leaves $4.9 million of forecasted expenditures unexplained. It appears that the Company reserved this amount as a placeholder for additional potential projects that may arise in 2021 but are not yet known. As stated earlier, the Commission has disallowed forecasted amounts that are merely placeholders for unknown and unquantifiable projects. Therefore, I recommend that the $4.9 million be removed from the 2021 capital expenditures in this rate case.

With regard to those projects identified in Mr. Blumenstock's direct testimony, I will address them later in my testimony under 2021 Conceptual Projects.

9. LVD Substations Rehabilitation

On line 19 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $14,500,000 for the year 2021 to rehabilitate and replace transformers and related equipment. The reason provided on page 185 of Mr. Blumenstock's testimony is that these transformers need to be replaced in 2021 because they pose an imminent threat of failure. In discovery, the Company was asked to explain why it is waiting until 2021 to undertake replacement of the transformers if there is an imminent threat of failure. The response to discovery request AG-CE-999, which is included in Exhibit AG-1.12, states that the Company needs to address other priorities and lacks sufficient inventory of transformers to potentially address the problem sooner.

In discovery, the Company was also asked to identify the specific projects that make up the $14.5 million in capital expenditures and provide specific reasons to justify the imminent threat of failure. In the detail schedule provided with discovery response AG-CE-997 and included in Exhibit AG-1.12, the Company shows 26 projects. Six of the projects on lines 15 to 20 of the schedule are described as working clearance code violations. The total amount of the six projects is $3.0 million. These transformers have been in place for several years and do not appear to pose any imminent threat of failure. The reason for replacement has been misstated and the Company has not made a convincing case that those six transformers need to be replaced in 2021 because of an imminent threat of failure. Therefore, I recommend that the Commission remove the $3.0 million from the Company's forecasted 2021 capital expenditures in this rate case.

With regard to the remaining projects listed on the schedule, I will address them later in my testimony as part of a larger group of projects that have not been adequately justified for inclusion in the projected rate base in this rate case.

10. LVD Lines Rehabilitation

On line 20 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $20,597,000 for the year 2020 and $37,723,000 for 2021 to rehabilitate LVD lines. In discovery, the Company was asked to provide the detail components of the forecasted spending along with related work units. In the detail schedule provided with discovery response AG-CE-1000, which is included in Exhibit AG-13, the Company shows two components: Imminent Rehabilitations and Security Assessment Repairs. In addition to the historical and forecasted amounts for each component, the Company also provided the number of units completed and forecasted to be completed from 2014 to 2021.

In Exhibit AG-1.14, I calculated the average cost per unit for the three historical years 2017 to 2019 for the Imminent Rehabilitation projects. The average cost per unit during the historical three-year period was $2,166,000. By applying that average historical unit cost to the forecasted units, I have determined that the Company's forecasted costs for Imminent Rehabilitations for 2020 and 2021 are overstated. My calculations show that the forecast for 2020 should be $5,701,000 for 2,632 units, and for 2021 it should be $8,913,000 for 4,115 units. Instead, the Company has forecasted $10,117,000 and $11,893,000 for 2020 and 2021, respectively.

The Company has not provided any explanation or justification in testimony and in discovery responses to support the significant increase in unit costs. Therefore, I recommend that the Commission remove the excess amounts of $4,416,000 for 2020 and $2,980,000 for 2021 from this rate case.

For the Security Assessment Repairs program, the Company reported that the work units prior to 2019 reflected the number of orders received, while from 2019 forward it reports the number of circuits repaired. Therefore, for my analysis, I calculated the cost per circuit completed in 2019 based on actual expenditures of $5,061,000 and 69 circuits completed. The unit cost is $73,348 per circuit. I applied that unit cost to the 134 forecasted number of circuits to be completed in 2020 and determined that the Company's forecast for that year is approximately $600,000 higher than my calculation. I find this forecast reasonable and do not propose any adjustments for the 2020 expenditures.

However, with regard to the 2021 forecasted costs, I find the Company's forecast is significantly overstated. By applying the 2019 cost per circuit of $73,348 to the 215 forecasted units for 2021, I have determined that a reasonable forecast would be $15,770,000. Instead, the Company has forecasted $25,830,000 for 2021. The difference is $10,060,000. Exhibit AG-1.14 shows the calculations.

The Company did not provide any explanation or justification in testimony and in discovery responses to support the significant increase in forecasted unit costs. Therefore, I recommend that the Commission remove the excess amounts of $10,060,000 for 2021 from this rate case.

In total, for this program, I recommend the disallowance of capital expenditures $4,416,000 for 2020 and $12,980,000 for 2021.

<u>11. Grid Storage</u>

On line 22 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $4,985,000 for 2020 and $10,000,000 for the year 2021 to install new batteries in certain areas of the electric distribution system. Beginning on page 195 of his direct testimony, Mr. Blumenstock discusses the Company's plans to experiment with battery storage along certain segments of the distribution electric grid. In discovery, the Company was asked to provide the current cost of battery storage, the assumptions made in the Company's IRP, the amount of battery storage planned for installation between 2025 and 2032, lessons learned from previous pilot programs, the basis for the $10 million of costs estimated for 2021, and the cost savings and benefits that would accrue to customers from the installation of battery storage along the distribution grid.

In response to discovery requests AG-CE-1004, 1006 and 1007, which are included in Exhibit AG-1.30, the Company provide some of the requested information and skipped over much of it. First, with regard to cost, the company stated that the estimated cost for battery storage is $4.9 million per MW based on a four-hour duration of storage capacity. This is a very high cost for a short period of backup capacity. Second, in the discovery response (AG-CE-1006d), the Company restated the fact that in the Company's 2018 IRP batteries were not selected as an economical electric supply solution until perhaps 2032, assuming significant improvement in performance and cost reduction. Third, no information was provided about a planned large-scale installation of battery storage between 2025 and 2032.

Fourth, The Company has already had experience with two battery storage pilot programs and has accumulated important lessons learned from those pilot programs, as identified in discovery response AG-CE-1004e. It is not clear how spending an additional $15 million between 2020 and 2021, with no economic solution in sight before 2032, will add anything additional of great value to what is already known. Fifth, the Company would not provide any specific information to show how it arrived at the $10 million cost forecast for 2021.

Sixth, the Company could not identify any near-term cost savings or financial benefits accruing to customers from spending $15 million over the next two years on additional pilot programs. The only identified benefit of potentially deferring $5.1 million in other capital projects over 10 years is not sufficient to justify spending $15 million in 2020 and 2021. This is not an economical cost benefit tradeoff. The project simply increases costs to customers with insufficient cost offsets.

In summary, the Company has not made a compelling case that further capital spending on Grid Storage is justified at this time. Therefore, I recommend that the Commission remove both the $4,985,000 from the 2020 capital expenditures and $10.0 million for 2021 from this rate case. If the Commission concludes that there is some merit to the 2020 program, it should at least remove the 2021 forecasted capital expenditures until the Company can show further progress was made from the 2020 capital spending on this program.

12. HVD Lines and Substations Capacity

On line 25 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $20,203,000 to add HVD lines and expand substations to accommodate increased demand capacity. In response to discovery request ST-CE-419, which is included in Exhibit AG-1.15, the Company provided a detail schedule showing the historical and projected capital expenditures and work units from 2014 to 2021. The detail schedule shows five work components and a TBD line.

The TBD line in the amount of $2,084,000 seems to include potential costs for projects not yet known and functions as a placeholder. As stated earlier, the Commission has ruled in prior rate cases that placeholder amounts should not be included in rate base. Therefore, I recommend that the $2,084,000 forecasted for 2021 be removed from capital expenditures in this rate case.

13. HVD Lines Interconnections

On line 31 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $2,062,000 for 2021 to build new interconnection lines to solar generation projects not yet built. On page 223 of his testimony, Mr. Blumenstock states that the Company expects to identify the specific locations of the new power plants later in 2020. In discovery, the Company was asked to provide a list of solar projects with the project timeline from start to completion for each project. In the discovery response AG-CE-1099, which is included in Exhibit AG-1.16, the Company stated that it has not yet identified the locations for the solar projects.

It is apparent from Mr. Blumenstock's testimony and the discovery response that the proposed line interconnections are very conceptual in nature with no specific locations and details yet known. The proposed capital expenditures of $2,062,000 for 2021 are premature given that the specific time when they will be incurred is still unknown.

Therefore, I recommend that the Commission remove the capital expenditures for this project from the projected rate base in this rate case.

14. Tools

On line 49 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of \$5,691,000 for the year 2020 and \$5,792,000 for 2021 to purchase new tools for employees and their trucks. In discovery, the Company was asked to provide the detail components of the forecasted spending along with related work units. In the discovery responses ST-CE-430 and AG-CE-1100, which are included in Exhibit AG-1.17, the Company shows two components: Truck Tool Packages and Other Capital Tools. In addition to the historical and forecasted amounts for 2017 to 2020 for each component, the Company also provided the number of truck tool packages from 2016 to 2020.

In Exhibit AG-1.18, I calculated the average cost per truck tool package for the two historical years 2018 and 2019. Where I would normally use a three-year average, 2017 costs were significantly lower than the other two years. It appears that 2017 was an unusual year and an outlier that would depress the average cost. Therefore, based on the 2018 and 2019 costs and units, the average cost per package during the historical two-year period was \$34,387. By applying that average historical unit cost to the forecasted units, I have determined that the Company's forecasted costs for the Truck Tool Packages for 2020 is overstated and the 2021 forecast is in line with historical trends. My calculations show that the forecast for 2020 should be $1,616,000 for 47 packages. Instead, the Company has forecasted $2,736,000.

The Company did not provide any explanation or justification in testimony or in discovery responses to support the significant increase in truck package costs. Therefore, I recommend that the Commission remove the excess amounts of $1,120,000 for 2020 from this rate case.

With regard to the Other Capital tools, in Exhibit AG-1.18, I calculated the average cost incurred during the three historical years 2017 to 2019 at $1,844,000. In comparison, the Company's forecasted costs of $2,955,000 for 2020 and $3,674,000 for 2021 are significantly overstated. For 2020, the difference is $1,111,000, or 60% above the three-year average, and for 2021, the difference is $1,830,000, or nearly 100%.

The Company did not provide any explanation or justification in testimony and in discovery responses to support such large increases over the average capital spending on tools over the most recent three years. Therefore, I recommend that the Commission remove the excess amounts of $1,111,000 for 2020 and $1,830,000 for 2021 from this rate case.

In total, for this capital expenditure category, I recommend that the Commission remove $2,231,000 for 2020 and $1,830,000 for 2021 from the projected rate base.

15. System Control Projects

On line 50 of Exhibit A-29 (RTB-2), the Company forecasted capital expenditures of $4,022,000 for the year 2020 and $4,170,000 for 2021 to install devices and equipment to allow remote operation of the electrical grid. In discovery, the Company was asked to provide the detail components of the forecasted spending along with related work units from 2017 to 2020. In the discovery responses ST-CE-432 and AG-CE-1102, which are included in Exhibit AG-1.19, the Company shows five components. My analysis determined that for four of the five components, the projected costs for 2020 and 2021 appear reasonable.

However, with regard to the HVD Remote Control and Control Capabilities item, the forecast for 2020 and 2021 are overstated. In response to discovery response ST-CE-432, the Company stated that it has reduced its projected spending for the entire category for 2020 from the amount of $4,022,000 previously forecasted. It appears that the HVD Remote Control item is the biggest change with no capital expenditures forecasted for 2020. The revised forecast for 2020 received from the Company in response to discovery is now $2,706,000. Therefore, I recommend that the Commission remove the difference of $1,316,000 from this rate case.

With regard to the forecasted capital spending for the HVD Remote Control items for 2021, in Exhibit AG-1.20, I calculated the average cost per unit for the three historical years 2017 to 2019. The historical average cost per unit is $16,621. By applying this average historical unit cost to the forecasted 62 units, I have determined that a reasonable forecast of costs for 2021 should be $1,031,000. Instead, the Company has forecasted $2,305,000. The difference is $1,274,000.

The Company has not provided any explanation or justification in testimony and in discovery responses to support the significantly higher amount than experienced over the past three years on a unit cost basis. Therefore, I recommend that the Commission remove the excess amounts of $1,274,000 for 2021 from this rate case.

In total, for this capital expenditure category, I recommend that the Commission remove $1,316,000 for 2020 and $1,274,000 for 2021 from the projected rate base.

16. 2021 Conceptual Projects

In Exhibit A-42 (RTB-15), the Company listed hundreds of individual projects with the related cost and number of units, where applicable, which are included in 2021 capital expenditures and the projected rate base in this rate case. In Exhibit A-41 (RTB-14), the Company also provided general descriptions of the categories of projects included in Exhibit A-42 and the supporting Confidential Workpaper RTB-5. The Company titled the schedule in Exhibit A-41 as a Summary of Selected Distribution Project Concept Approvals. The schedule show that some projects have received concept approval as of January 2020 and others have not, and review and approvals are still in progress.

In my analysis of the information provided by the Company in Confidential WP-RTB-5, I focused my attention on projects of $1 million and higher. As a result of that analysis, I identified 27 projects where the project's forecasted cost exceeded $1 million. Because conceptual project costs in the early stage of concept development often change both in cost and timing after they enter the phase of design and construction bidding, in discovery I requested the Company to provide (1) confirmation of the latest cost of the project, (2) the amount included in the projected capital expenditures in this rate case, (3) the project document with approval signatures showing the most recent forecast amount included in this rate case, (4) the concept cost approval documents for projects undertaken in 2019 and to be undertaken in 2020 of $1 million and greater, and (5) any amounts to be spent in 2020 or already spent in 2018 and 2019.

In response to discovery request AG-CE-1120, which is included in Exhibit AG-1.21, the Company stated a general objection to providing the requested information and answered some of the questions, as follows. It refused to provide a copy of the executed approval document instead stating that the projects had received all necessary approvals and signatures. It stated that all conceptual costs shown in the documents in Confidential WP-RTB-5 are the costs that have been included in capital expenditures for 2021 in this rate case, and the Company had not updated those conceptual cost estimates. It stated that no historical spending has occurred, and the concept cost approvals pertain to the 2021 test year. The Company refused to provide any similar concept approval documents for projects in 2019 and 2020 of $1 million or greater, claiming that it would be unduly burdensome.

After reviewing the conceptual project approval documents for the 27 projects for 2021, I have determined that all 27 projects should be disallowed in the total amount of $107,697,000. In Exhibit AG-1.21, I have identified those projects and included the Company's response to discovery request AG-CE-1120. In Exhibit AG-1.22 Confidential, I have provided a listing of the projects with the applicable amount to be disallowed and included the pertinent project documents provided by the Company in Confidential WP-RTB-5. It is premature to include the conceptual cost of such projects in rate base until they progress past the design stage and the cost and timing of the projects have been established with some certainty.

Exhibit A-41 clearly shows that several of the project categories have not even received conceptual project approval. However, the Company still seeks to include the cost of those projects in rate base and begin to recover depreciation and the return on investment on projects that are very preliminary. For those projects that supposedly received internal approval, the Company also has not provided any evidence of project approval by the required level of management with signature and date of approval. The project documents and the Company's responses to discovery do not provide sufficient assurance as to when or if the costs will be incurred in the amounts projected.

In summary, the Company's proposal to include the capital expenditures for the 27 projects is incomplete, premature and unreasonable. I recommend that the Commission remove the $107,697,000 of capital expenditures for 2021 from this rate case.

C. Power Generation - Capital Expenditures

As shown on page 1 of Exhibit A-12 (SAH-3), Schedule B-5.2, the Company incurred capital expenditures of $175.7 million for Power Generation plant in 2018, and forecasted $17.0 million for 2019, $119.6 million for 2020, and $161.1 million for 2021. Included in these total amounts are capital expenditures for Steam (Fossil Fuel) Power Generation, Hydro Power Plants, Pumped Storage Generation (Ludington), and Other Production Plant. In my testimony below, I will evaluate and propose adjustments to several of these programs and component projects.

1. Dry Ash Cell 6 Landfill Construction

On line 15 of page 9 of Exhibit A-12 (SAH-3), Schedule B-5.2, the Company forecasted capital expenditures of $5,483,000 for the year 2021 to build an onsite landfill to store fly ash from the Campbell power plant. According to page 63 of Mr. Scott Hugo's direct testimony, the Company will not complete the design of the landfill until sometime in 2020 with construction anticipated in 2021. In discovery, the Company was asked to provide information on permits received to allow it to build the landfill, the basis for the cost of the project and whether any construction bids had been received yet.

In response, the Company stated that a new construction permit from the Michigan Energy and Great Lakes Environmental Division (EGLE) will be required. The Company plans to submit the permit request in August 2020 and EGLE may take 4 months to approve it. The Company has not yet bid out the projects and plans to do so by early second quarter of 2021. Exhibit AG-1.23 includes the Company's response to discovery request AG-CE-1188.

From the Company's response to discovery, it is evident that this project may start sometime in late 2021 but is not likely to be completed in 2021 as planned. Therefore, it is premature to include the forecasted amount in the projected rate base. I recommend that the Commission remove $5,209,000 of capital expenditures for this project from this rate case. The amount of $5,209,000 reflects the total forecasted project amount of $5,483,000 less the contingency amount of $274,000 previously removed under the Contingency Capital Expenditures section of my testimony.

2. Karn Units 1 and 2 Decommissioning

On line 16 of page 9 of Exhibit A-12 (SAH-3), Schedule B-5.2, the Company forecasted capital expenditures of $10,296,000 for the year 2021 to separate and rebuild several utilities and systems at the Karn power plant in order to decommission the Karn Units 1 and 2. In addition, the Company forecasted $890,000 of decommissioning costs for 2019, $15,675,064 for 2022 and $1,789,545 for 2023. Mr. Hugo describes some of the systems that need to be reconfigured beginning on page 66 of his direct testimony.

In discovery, the Company was asked to explain why decommissioning work needs to start as early as 2020 and 2021, when the plant is not scheduled to be decommissioned until May 2023. The Company was also asked to provide the basis for the cost estimate and whether contractor bids had been received. In response to discovery request AG-CE-1189, which is included in Exhibit AG-1.24, the Company stated that the retirement of Karn 1 and 2 requires separation of various systems from the other generation units that will continue to operate. However, the response basically repeats the information provided in Mr. Hugo's testimony and does not provide any additional explanation or information. With regard to contractor bids, the Company stated that the work has not been bid out yet and would likely be bid out late in 2020 and through 2021.

From the Company's response to discovery, it is evident that this project may not start in earnest until sometime in late 2021. Therefore, it is premature to include the forecasted amount of capital expenditures for 2020 and 2021 in the projected rate base in this rate case. I recommend that the Commission remove the $890,000 forecasted for 2020 and $9,781,000 of capital expenditures for 2021 from this rate case. The amount of $9,781,000 reflects the total forecasted project amount of $10,296,000 less the contingency amount of $515,000 previously removed under the Contingency Capital Expenditures section of my testimony.

3. Jackson Warehouse

On line 14 of page 8 of Exhibit A-12 (SAH-3), Schedule B-5.2, the Company forecasted capital expenditures of $4,400,000 for the year 2020 to build a new warehouse in Jackson, MI, to house distribution and generation plant parts and tools. Mr. Hugo briefly describes this project on page 78 of his direct testimony.

In discovery, the Company was asked to answer several questions and provide the basis for the forecasted cost for 2020 and any bids received for the construction of the building. In response to discovery request AG-CE-1197, which is included in Exhibit AG-1.25 Confidential, the Company provided an internal cost estimate totaling $3.4 million including a $282,000 contingency cost. In addition, the Company provides the results of four construction bids it received with the lowest at approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

From the Company's response to discovery, it is evident that the cost of this project is overstated by approximately $780,000 after allowing for the removal of the contingency shown on page 8 of Exhibit A-12, Schedule B-5.2. Therefore, I recommend that the Commission remove the $780,000 capital expenditures for 2020 from this rate case.

4. Hardy Auxiliary Spillway Remediation

On line 17 of page 8 and line 27 of page 9 of Exhibit A-12 (SAH-3), Schedule B-5.2, the Company forecasted capital expenditures of $1,000,000 for the year 2020 and $8,000,000 for 2021 to undertake a remediation of the Hardy hydro facility spillway. Mr. Hugo briefly describes this project on page 85 of his direct testimony, where he also stated the need to review the option for retirement of the facilities along with performing alternative design evaluations.

In discovery, the Company was asked to provide the basis for the $8.0 million cost estimate and related cost components, state whether any construction bids had been received, and explain why the Company would spend $9 million between 2020 and 2021 before the retirement study had been completed. In response to discovery request AG-CE-1200, which is included in Exhibit AG-1.26, the Company stated that the $8.0 cost estimate was based on engineering, ancillary studies, consultants, and contractor evaluations. No supporting data of the cost components were provided. It also stated that it is has not selected a construction contractor and is still performing preliminary design for any needed remediation. In response to the question of why it would proceed with capital spending of $9 million between 2020 and 2021 before a retirement study was completed, the Company disclosed that the entire project may cost in excess of $50 million. It also outlined the requirement for a comprehensive analysis with a timeline spanning from August 2020 to May 2022.

From the Company's response to discovery, it is evident that this project still requires considerably more analysis than has been done to date, before any significant capital spending should be undertaken. Therefore, it is premature to include the forecasted amount of capital expenditures for 2020 and 2021 in the projected rate base. I recommend that the Commission remove the $900,000 of forecasted expenditures for 2020 and $7,200,000 of capital expenditures for 2021 from this rate case. The 2021 amount reflects the removal of contingency costs previously addressed under the Contingency Capital Expenditures section of my testimony.

5. Ludington Upgrade and Overhaul

On line 20 of page 8 of Exhibit A-12 (SAH-3), Schedule B-5.2, the Company forecasted capital expenditures of $12,707,000 for the year 2020 to perform the upgrade and overhaul of the Ludington Unit 3 power plant. Mr. Hugo briefly describes this project on page 89 of his direct testimony.

In discovery, the Company was asked to provide the basis for the forecasted capital expenditure amount and related cost components. The Company was also asked to state whether it received multiple contractor bids and to provide a copy of the winning bid. In response to discovery request AG-CE-1202, which is included in Exhibit AG-1.27, the Company stated that the 2020 cost forecast was in line with the 2018 cost forecast. No supporting data of the cost components were provided. It also stated that it evaluated three construction contractors and selected the winning bidder in 2010. However, it could not provide a copy of the winning bid for the work to be performed in 2020.

From the Company's response to the discovery request, it is evident that the Company has not provided any of the information requested to allow me to validate the accuracy and reasonableness of the capital expenditures forecast. Therefore, I recommend that the

Commission remove the entire amount projected for 2020 of $12,707,000, less the contingency amount of $3,177,000 previously removed in the Contingency Capital Expenditures section of my testimony because those expenditures are not appropriate for recovery in this rate case. The net amount to be removed is $9,530,000.

6. Ludington Reservoir Liner Replacement

On line 36 of page 9 of Exhibit A-12 (SAH-3), Schedule B-5.2, the Company forecasted capital expenditures of $6,610,000 for the year 2021 to replace the liner of the water reservoir at the Ludington power plant. Mr. Hugo briefly describes this project on page 92 of his direct testimony.

In discovery, the Company was asked to provide the basis for the forecasted capital expenditure amount and related cost components. The Company was also asked to state whether it received multiple contractor bids and to provide a copy of the winning bid. In response to discovery request AG-CE-1205, which is included in Exhibit AG-1.28, the Company stated that the 2021 cost forecast was based on an engineering study completed by a consultant. No supporting data of the cost components were provided. It also stated that the Company is still working on the design phase of the project and contractor bid requests would not be issued until later part of 2020.

From the Company's response to the discovery request, it is evident that the Company has not provided any of the information requested to allow me to validate the accuracy and reasonableness of the capital expenditures forecast. In addition, the timing for completion of the project is still uncertain given that the design phase is not yet completed, and contractor bids will not be requested until late in 2020.

Therefore, I recommend that the Commission remove the entire amount projected for 2021 of $6,610,000, less the contingency amount of $992,000 previously removed in the Contingency Capital Expenditures section of my testimony, because those expenditures are not appropriate for recovery in this rate case. The net amount to be removed is $5,618,000.

7. 2019 Actual Power Generation Capital Expenditures

In discovery, the Company was asked to provide the actual capital expenditures incurred for the year 2019 in the power generation area. In response to discovery request AG-CE-1220, which is included in Exhibit AG-1.29, the Company reported that in 2019 it incurred $169,180,000 of actual capital expenditures in the power generation area. This amount is $4,864,000 lower than the forecasted amount of $174,044,000 included in this rate case.

The Company also reported that for the first 9 months of 2020, its expenditures are running above plan. However, the year is not yet completed, and with the slowdown in activity due to the coronavirus pandemic, it is likely that the Company will be at or below the forecasted amount for the year 2020.

However, for 2019 the Company should not be allowed to include costs in rate base which it did not spend. It would be unreasonable and unfair for customers to pay for the depreciation expense and the return on capital investments that the Company did not actually incur in 2019. Therefore, I recommend that the Commission remove the $4,844,000 from rate base in this rate case.

D. Operations Support - Capital Expenditures

In Exhibit A-12 (LDS-1), Schedule B-5.6, the Company forecasted capital expenditures for Asset Preservation of $20.7 million for 2019, $21.8 million for 2020, and $64.9 million for the year 2021. In comparison, the Company incurred capital expenditures of $26.2 million in 2018. Included in the forecasted capital expenditures for 2020 and 2021 are capital expenditures for several new service centers, a new Unified Control Center (UCC), and a new electrical training center, called Grand Rapids Circuit 501. Exhibit A-94 (LDS-3) shows the specific expenditures. In my testimony below, I will address each of those projects.

With regard to the UCC, although Company witness Latina Saba sponsored testimony and exhibits on the capital expenditures, Company witness Brenda Houtz provided additional details on the project in her testimony and also provided responses to discovery requests. Company witness Patrick Ennis also answered discovery requests related to these expenditures.

1. New Service Centers

On lines 15, 16 and 19 of Exhibit A-94 (LDS-3), the Company shows forecasted capital expenditures for the Lansing, Hastings and Kalamazoo Service Centers. The total forecasted capital expenditures amount for the three centers for 2020 is $2,746,000. For the year 2021, the total forecasted amount is $25,567,000.

In discovery, the Company was asked to provide comparative information between the new and old centers, such as the number of square feet of space, the number of employees, the type of operations housed at each center, the total cost of each projects by business line in total for the company, and an explanation for the difference in cost between some of the centers. In its response to discovery request AG-CE-1345, which is included in Exhibit AG-1.31, the Company provided the square feet of space and number of employees housed at the old service centers, but did not provide the same information for the new proposed service centers. This lack of information is evidence that development of the new centers is not sufficiently advanced and the Company has not yet established the design parameters of the new service centers, their size and space requirements.

Additionally, the information provided in discovery response AG-CE-1345 raise questions about the type of operations housed at some of the service centers. For example, at the Lansing and Kalamazoo Service Centers, the Company houses functions, such as People & Culture, Public Affairs, Rates and Regulation, and Transformation. It is not clear what functions some of these operations actually perform and why those functions cannot be supported from the Company's headquarters in Jackson, MI. The Company's headquarters building is less than 40 minutes by car from Lansing, MI, and about an hour from Kalamazoo, MI. It seems unnecessary and wasteful to build large service centers to house functions that could be performed at the Company's headquarters.

In response to discovery request AG-CE-1345, the Company also provided the total cost of the new service centers split between the electric and gas business. Attachment 1 shows that the three centers combined will cost nearly $100 million between 2019 and 2022, if completed as planned, with the electric business absorbing the largest share of this cost. The schedule also shows an apparent error in the capital expenditures included in the Company's Exhibits A-12 (B-5.6) and A-94 filed in this case. According to the detailed schedule provided in Attachment 1 to AG-CE-1345, the amount of capital expenditures allocated to the electric business for 2020 should have been $1,782,000 instead of the $2,746,000 amount included in the exhibits.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR 2020 AND 2021 FOR THE THREE SERVICE CENTERS?

A. From the limited information provided by the Company in testimony and in response to discovery, it is apparent that the projects are still in the very early stages of design and development. Furthermore, the timing of when the forecasted expenditures are likely to occur in 2020 and 2021 is suspect. According to the information shown in Exhibit AG-

1.31, the Company may have done some early engineering work in 2019 and had plans to acquire the necessary land in 2020 with construction and furnishings to be completed in 2021 and 2022.

Given the lack of specifics about the size of the square feet of space, employees and operations to be housed at the new centers, it is evident that the projects are not well advance to result in capital expenditures in 2020 and 2021 to the level forecasted. It is premature to include very preliminary and uncertain capital expenditures in rate base for the Company to earn a return and recover depreciation expense before plans for construction of the facilities have been finalized and are certain to occur. Additionally, the amount of capital expenditures included in the exhibits for 2020 is erroneous

Therefore, I recommend that the Commission remove the 2020 forecasted expenses and move those expenses to 2021. The 2021 forecasted expenses should be removed given that likely those expenditures would be delayed to 2022. As such, the Commission should remove $2,746,000 from 2020 and reduce the 2021 forecasted capital expenditures by $23,785,000 ($25,567,000 - $1,782,000).

2. New Training Center

On lines 13 of Exhibit A-94 (LDS-3), the Company shows forecasted capital expenditures for the Grand Rapids Circuit 501 new training center. The total forecasted capital expenditures for this new training center are $1,570,000 for 2019, $2,805,000 for 2020, and $26,484,000 for 2021. Beginning on page 19 of her direct testimony, Ms. Saba dedicates less than a page to explain this large and costly project. She states that this proposed project is in its early stages of development and is intended to be utilized as a learning and development center. The rest of the testimony describes general corporate goals.

In discovery, the Company was asked to provide certain basic information, such as the number of square feet of space for the proposed facility, the total cost of the facility from inception to completion, the cost/benefit analysis to justify the investment and other relevant information. In the response to discovery request AG-CE-1348, which is included in Exhibit AG-1.32, the company stated that the anticipated size of the building will be 60,000 square feet and will cost $45 million to be spent between 2021 and 2022. Apparently, the previously forecasted expenditures for 2019 and 2020 in the filed exhibits totaling $4,375,000 will not be spent.

In the discovery response the Company also stated that no cost/benefit analysis had been completed. In response to a question about how the Company currently imparts learning and development to employees, the Company listed several programs and locations throughout its service area when where it currently performs those functions. No information was provided in the discovery response or in direct testimony why the current process is no longer effective and why a new center at a cost of $45 million is needed to impart knowledge.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR 2019 THROUGH 2021 FOR THE GRAND RAPIDS CIRCUIT 501 PROJECT?

A. There are two basic problems with the proposed Grand Rapids circuit 501 project. First, it has not been adequately justified. The Company has not made a compelling business case that the new employee training and development center is needed. No cost/benefit analysis has been presented in this rate case to justify spending $45 million on this project.

Second, the proposal is in the very early stage of development and is no more than a mere concept at this time. Assuming the project had been justified, the timing of the capital spending is also uncertain. The bulk of those capital expenditures would not likely occur until after the end of the 2021 projected test year. It is premature to include very preliminary and uncertain capital expenditures in rate base for the Company to earn a return on investment and recover depreciation expense before plans for construction of the facilities have been finalized and are certain to occur.

I recommend that the Commission remove the entire forecasted capital expenditures for this project from 2019 through 2021. Therefore, the Commission should remove $1,570,000 from 2019, $2,805,000 for 2020 and $26,484,000 for 2021.

3. Unified Control Center

On lines 14 of Exhibit A-94 (LDS-3), the Company shows forecasted capital expenditures for the new UCC. The total forecasted capital expenditures for this new facility is $1,000,000 for 2021. Beginning on page 18 of her direct testimony, Ms. Saba briefly explain the goals of the project. Company witness Brenda Houtz expands further on that information beginning on page 28 of her direct testimony.

In discovery, the Company was asked to provide certain basic information on the proposed project, such as the number of square feet of space for the facility, the total cost from inception to completion, and the need to replace the current facilities with a new combined center. In the response to several discovery requests, which are included in Exhibit AG-1.33, the Company reported that the new facility will be about 100,000 square feet in size. On the cost side, it reported that the new facility will cost in excess of $100 million, but the timing of the expenditures differs between the response received from witness Ennis in AG-CE-1347 from the response received from witness Houtz in AG-CE-1178. The response from Ms. Houtz has half of the $100 million cost occurring in 2022, while Mr. Ennis's response spreads the capital expenditures over the three years from 2022 to 2024. The location of the new facility has not yet been determined.

It is also uncertain what the $1 million included in this rate case will be spent for. On page 3 of her direct testimony, Ms. Houtz states that the amount is for land purchase. However, in response to discovery, she now states that the $1 million is to complete concept scope.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR 2021 FOR THE UCC PROJECT?

A. The Company has requested to include $1 million to perform a concept scope on a project that has not been adequately justified. Despite several pages of direct testimony by Ms. Houtz, there is insufficient justification why a new combined control center is necessary and what real cost benefits and other material benefits it will actually achieve. In fact, having two separate centers, as is the case today, may be advantageous to minimize the higher risk that would result from a combined center, should a major disaster or catastrophic event occur that would impact the unified center. The Company has not adequately answered those concerns. From the discovery responses, it appears that the Company may be considering building a second back up facility at an additional cost.

In response to the question about the limitations posed by the current centers that the UCC will solve, the Company provided general answers with no quantitative or qualitative justifications (AG-CE-1173f). It is not clear why with today's distributed information technology the Company cannot harness the flexibility of IT technology between the two centers that already provide a certain degree of disaster risk mitigation.

In summary, it is premature for the Commission to approve any recovery of capital expenditures for this project until a compelling business case is made by the Company on the necessity for the entire project. Therefore, I recommend that the Commission remove the $1 million of capital expenditures included by the Company in 2021 for this project.

E. Fleet Services - Capital Expenditures

In Exhibit A-12 (KPJ-1), Schedule B-5.7, the Company forecasted capital expenditures for Transportation Equipment of $28.7 million for 2019, $33.2 million for 2020, and $62.7 million for the year 2021. In comparison, the Company incurred capital expenditures of approximately $18.0 million in 2018. Included in the forecasted capital expenditures for the year 2021 are capital expenditures of $24.5 million for a planned increase in employees in the Electric Distribution area, and $7.2 million for a new Telematics fleet management system.[9]

In his direct testimony, Company witness Kyle Jones discusses the level of capital expenditures, as well as his proposal to increase capital spending on the fleet of cars, trucks and equipment to a company-wide annual level of $51.7 million. Mr. Jones apparently has begun this expanded program in 2020 with approximately $31.8 million assigned to the electric business.[10] In Case No. U-20134 and U-20322, the Company had proposed the same spending level for 2019. Apparently, the Company decided to postpone implementation of the higher expenditure program given that Exhibit A-12, Schedule B-5.10, in this rate case shows only $13.2 million of capital expenditures for 2019.

[9] Exhibit AG-1.34 includes Company workpaper WP-KPJ-1 showing the capital expenditures detail components by forecast period.
[10] Kyle Jones direct testimony beginning at page 8.

In discovery, the Company was asked to provide the actual capital expenditures for fleet purchases from 2016 to 2019, and the forecasted amounts for 2020, 2021. The request also asked for total company expenditures and those specifically to the electric business. The attachment to the Company's response to data request AG-CE-1344 shows that total-company capital expenditures have increased significantly from $26 million in 2016 to nearly $50 million in 2019. However, the portion of capital spending allocated to the electric business has varied significantly from 71% in 2016 to a low of 37% in 2016. According to the schedule provided in discovery, the allocation of capital spending for the electric business is forecasted to be approximately 60% for the years 2020 and 2021. Exhibit AG-1.34 includes the discovery response with related attachment showing this information.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSAL TO INCREASE CAPITAL SPENDING IN ORDER TO ACCELERATE THE REPLACEMENT OF TRANSPORTATION EQUIPMENT AND REDUCE THE AVERAGE AGE OF THE FLEET?

A. In Case Nos. U-20134 and U-20322, which are the Company's previous electric and gas rate cases, Company witness Bruce Straub made similar proposals to increase the company-wide capital spending for transportation equipment to $51.7 million, and provided the same study performed by Utilimarc in an attempt to justify the increase in capital expenditures beginning in 2019. My assessment in this rate case to a large degree will mirror the assessment I made in Case Nos. U-20134 and U-20322. I also made the same assessment in the recent Company's gas rate case No. U-20650.

In summary, my assessment is that the Company has not made a convincing case that undertaking a capital spending program which doubles the amount of annual expenditures from the current level of $24 million to nearly $52 million is economically justified. In my testimony below I will discuss the major issues and shortcomings with the Company's proposal.

First, the Company attempts to make the case that its fleet of equipment is old and in disrepair and needs to be replaced at a faster rate than it has done historically. In his testimony, Mr. Jones discusses at length what he perceives to be the problems that require reducing the average life of the fleet. However, on page 7 and 8 of his direct testimony, Mr. Jones shows that the transportation fleet unit availability has been ranging from 98.4% to 99.3% since May 2017. The unit availability appears to be excellent, approaching almost 100%. This indicates that nearly in all cases when a vehicle or a piece of equipment is needed, one is available for use. To achieve this result, the equipment must be in relatively good shape, and that any repairs and maintenance have been done in a timely manner.

In discovery in Case No. U-20650, the Company was asked to provide the operating, maintenance and repair costs from 2009 to 2019 for the transportation fleet. The response to discovery request U20650-AG-CE-345 shows that over the 11-year period, these costs have increased at an average rate of 6.3%, with some variations from year-to-year. For 2020, the Company has forecasted a 6.1% increase in costs. This rate of increase in operating, maintenance and repair costs does not indicate that the fleet is deteriorating at a faster rate than normal. In other words, if the fleet was deteriorating significantly due to an extended replacement cycle, we should see a much greater increase in O&M costs over this time period. Exhibit AG-1.35 includes the Company's discovery response showing this information.

On page 26 of his direct testimony, Mr. Jones expresses a concern that O&M expense for the transportation fleet will begin to increase at an annual rate of 21% and reach $82 million over a ten-year period if a higher spending level is not implemented. He made the same claim in Case No. U-20650. Asked in discovery to explain how this amount was determined, the Company provided a calculation performed by Utilimarc. The calculation compares the O&M expense under the current rate of fleet replacement to the O&M expense under the $51.7 million annual spending level.

Interestingly, the O&M expense under the current spending level is escalated at an annual rate ranging from 5% to 29% over the 10-year period from 2018 to 2027, while the rate of increase for O&M expense under the Utilimarc's proposed capital spending level of $51.7 million declines from an annual rate of 5% to 1.8% over the same time period. It is under these divergent assumptions that the Company's reaches the conclusion that it must accelerate capital spending to buy more vehicles and equipment to replace the existing fleet at a faster rate. Exhibit AG-1.35 also includes the Company's response to U20650-AG-CE-347 with this information.

It is also noteworthy to point out that in Case No. U-20322, filed in November 2018, the Company forecasted that O&M costs for 2018 would reach $64 million and escalate to $93 million in 2019 and 2020 if the higher spending level was not approved in rates.[11] This prediction did not materialize.

Most importantly, the study performed by Utilimarc does not include the actual and forecasted O&M costs for operating, maintaining and repairing the Company's equipment fleet. Utilimarc used a composite O&M cost from other utilities where the firm has performed similar studies. In response to discovery, the Company could not provide the supporting data to the Utilimarc O&M information in order to assess the composition of the data and the comparability to the Company's costs. Using other utilities' O&M costs to assess the specific capital needs and fleet replacement cycle of the Company can lead to an "apples to oranges" comparisons and misleading results. Therefore, I find the validity of the study suspect.

Q. HAS THE COMPANY PERFORMED A COST/BENEFIT ANALYSIS TO JUSTIFY THE INCREASED CAPITAL SPENDING?

[11] MPSC Case U-20322, Exhibit AG-26.

A. No. The analysis performed by Utilimarc and the direct testimony of Mr. Jones lack even a rudimentary cost/benefit analysis to assess whether the proposed incremental capital investments over the next 10 years are justified by a reduction in O&M expense. Asked again in discovery in Case No. U-20650 if the Company had performed such a cost/benefit analysis, the Company responded that it had not performed that analysis.[12] The lack of an economic analysis is striking. It is imprudent to undertake such a large increase in capital spending without knowing that it will provide a net economic benefit on a net present value basis.

Q. WHAT IS YOUR ASSESSMENT OF THE INCREMENTAL $24.5 MILLION PROPOSED BY THE COMPANY FOR 2021 TO PROVIDE TRANSPORTATION EQUIPMENT TO NEW EMPLOYEES HIRED FOR ADDITIONAL ELECTRIC DISTRIBUTION FIELD WORK?

A. The Company has proposed $24.5 million of additional transportation equipment purchases in 2021 to supplement the base amount of $32.0 million of transportation equipment purchases forecasted for the year. This is a relatively large expenditure to provide new equipment for new hires relative to the base amount of purchases for equipment for the existing pool of employees. According to Mr. Jones, the additional equipment purchases will support 234 new employees in the electric distribution

[12] Exhibit AG-1.35, CECo response to U20650-AG-CE-345d.

operations. Exhibit AG-1.34 includes the information provided by the Company in response to discovery request AG-CE-1343.

The information provided by Mr. Jones does not match with the information presented by Company witness Detterman in Exhibit A-60 (DED-1). In that exhibit, Mr. Detterman shows that the number of employees dedicated to LVD and HVD distribution work was 1,257 in 2019 and that number is forecasted to increase to 1,400 employees in 2021. This is an increase of only 143 employees not 234. It appears that the requirements for additional transportation equipment presented by Mr. Jones are highly inflated by 91 employees, or approximately 40%.

Given this discrepancy and the likelihood that the Commission will not grant all the capital spending requested by the Company for new distribution projects, it is safe to assume that the incremental transportation equipment purchases presented by Mr. Jones will be at least 50% less than forecasted. Therefore, I recommend that the Commission remove at least $12.2 million of the $24.5 million requested.

Q. WHAT IS YOUR ASSESSMENT OF THE TELEMATICS FLEET MANAGEMENT SYSTEM PROPOSED BY THE COMPANY?

A. Beginning on page 27 of his direct testimony, Mr. Jones discusses the Telematics fleet monitoring and management system. Based on Mr. Jones' testimony and responses to discovery, the system appears to offer some useful features and functionalities which can reduce capital and O&M costs. Although the Company did not conduct a formal bidding process with multiple vendors, in response to discovery request U20650-AG-CE-348, the Company stated that it reviewed the functionality of two other systems and found the Utilimarc's Telematics system to be superior.

The Company plans to implement the new system beginning in October 2020 and have it fully functional during the 2021 projected test year. Exhibit AG-1.36 includes discovery responses U20650-AG-CE-348 and 349 showing this timeline and the Company's response stating that all system functions will be implemented simultaneously within the $7.2 million of capital expenditures proposed in this rate case.

In response to discovery, the Company also provided the calculation of the capital and O&M savings of nearly $11.5 million for both the electric and gas businesses from implementation of the Telematics system. Assuming the cost savings materialize, the new system seems to be a reasonable capital investment that pays for itself very quickly. These savings should begin to occur in the projected test year and need to be factored into the capital and O&M cost projections. Exhibit AG-1.36 includes the Company response to discovery request U20650-AG-CE-350 with the related pertinent attachment.

Q. WHAT IS YOUR OVERALL CONCLUSION AND RECOMMENDATION?

A. The information provided by the Company does not make a compelling case that the level of capital spending on transportation equipment should escalate to the level proposed in this rate case. Insufficient evidence has been presented to support the premise that transportation equipment is deteriorating at a faster pace than historically, and, as a result, O&M costs will be escalating significantly in coming years. To the contrary, the evidence shows a high unit availability rate of nearly 100%. Furthermore, the Company has not presented a cost/benefit analysis to justify the proposed increase in capital spending.

As shown in Exhibit AG-1.34, during the prior three years from 2017 to 2019, the Company has spent between $12.0 million and $35.4 million on the transportation fleet in the electric business. The average capital expenditures over the three-year period is $21,664,000.

Therefore, I recommend that the base capital expenditures for Transportation Equipment for the 2021 projected test year should be set at $21,664,000 instead of the Company's proposed $32,006,000. In addition, as stated earlier, the incremental capital expenditures for added employees in the Electric Distribution area should be set at $12.3 million. The Telematics capital expenditures should be self-funded by cost savings achieved by the implementation of this new system and therefore unnecessary to be included in this rate case.

In total, I recommend that the Commission only approve capital expenditures of $21,904,000 for 2020 and $34,151,000 for 2021, including fleet tools.[13] As a result, I

[13] For 2021: $21,664,000 (base) + 12,247,000 (incremental) + 240,000 (tools) = $34,151,000

recommend that the Commission remove $11,318,000 from the Company's 2020 forecasted expenditures, and $28,598,000 from the 2021 forecasted amount.[14]

F. Information Technology Projects - Capital Expenditures

In Exhibit A-12 (JDT-3), Schedule B-5.3, the Company shows total capital expenditures for Information Technology (IT) infrastructure and various projects. For 2019, the Company forecasted $56.4 million, for 2020 it forecasted $55.6 million, and for 2021 it forecasted $73.8 million. Capital expenditures for 2018 were slightly higher at $74.2 million. Included in the capital expenditures for 2020 and 2021 are several projects for which I will recommend disallowance of a portion or all of the forecasted capital spending. For the most part, these projects are in the conceptual stage or early stage of development and have not been sufficiently vetted or justified with commensurate benefits to meet the basic threshold for inclusion in rate base in this rate case.

The problem with including preliminary forecasted capital expenditures in rate base is evident in the forecasting approach described on page 33 of Company witness Jeffrey Tolonen's direct testimony. Here, he explains that the IT's investment forecasts begin with a Rough Order of Magnitude (ROM) estimate and these estimates can vary between -25% to +75% from actual capital expenditures. This range is a general industry standard and may not necessarily reflect the Company's situation. When project costs are estimated at the early conceptual phase, as many of the projects discuss later in my testimony are, it

[14] For 2020: $33,222,000 – 21,904,000 (base and tools) = $11,318,000. For 2021: $62,749,000 – 34,151,000 = $28,598,000.

is likely that the range of inaccuracy may be even larger. However, the Company has included those very rough estimates in the projected rate base in this case and seeks to recover a return and depreciation expense on forecasted investments that may not materialize. The Commission should reject the inclusion of costs in rate base that are uncertain to occur.

Many of the IT business projects discussed below are sponsored jointly by Mr. Tolonen and the Company witness sponsoring testimony for that business unit. Therefore, in discussing the details of the projects, I will make reference to the testimony of those other witnesses.

1. Dashboard and Website Redesign

In Table 4 on page 44 of his direct testimony, Company witness Steven McLean presents four IT projects. Two of the projects entail significant capital expenditures and related O&M expense. The first project is the Dashboard Redesign with capital expenditures of \$3,528,027 in 2021 and \$164,670 of O&M expense in the projected test year. The second project is the Website Redesign with capital expenditures of \$3,184,331 and \$434,445 of O&M expense. In total, the two projects would require approximately \$5.7 million in capital expenditures and \$600,000 of O&M expense in 2021.

In discovery, the Company was asked to identify the current phase of the projects, the total capital expenditures from inception to completions, the project cost estimate details and project approval documents, and other pertinent information to assess the reasonableness, timing and certainty of each of the projects. In response to discovery request AG-CE-1331, which is included in Exhibit AG-1.37, the Company provided some of the detailed information requested, but stated that it was no longer pursuing the two projects and instead wants to pursue a different project.

The new project, named Mobile Application, will cost approximately $10 million and appears to be at the very early concept stage. The key project deadlines provided in the discovery response show an investment planning stage to be completed by January 1, 2021, a plan and definition phase for the project in the spring of 2021, a project execution phase sometime in 2021 to 2022, and a project go-live date in the first quarter of 2022.

This information, plus a description of what the new application could accomplish was provide on June 18, 2020, six days before filing of Staff and intervenors testimony in this case. The discovery response included a couple of attachments on forecasted cost data and a general industry survey purporting to show that 30% of the Company's customers and particularly young people prefer to use their cell phone to access information from the Company's website.

Aside from the short notice and the inability to adequately evaluate this change in direction, the project is at an early stage of development that even calling it a conceptual project may be a misnomer. The justification offered by the Company for this new project needs to be more fully vetted with insufficient time to perform that task in this rate case. For example, the Company has not explained why it is reasonable or prudent to spend $10 million to develop an application (App) that would only be used by 30% of its customers and expect the other 70% of its customers to pay for it. Often companies that develop specialized Apps charge a monthly fee to customers who use the App to access information they believe is of value to them. It is unknown at this time if the Company explored such an option to lessen or offset the cost of development of the new App.

Similarly, it is not clear if the survey performed by Accenture and included as an attachment to the discovery response is reliable or self-serving, given the fact that Accenture provides consulting services and project implementation services for similar IT projects.

Furthermore, the Company's discovery response states that after completing this $10 million mobile App, it may still need to pursue the Website and Dashboard Redesign project sometime in the future at potentially an additional cost of $9.5 million. This disclosure raises even more concerns about the Company's capital spending plans.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR 2020 AND 2021 FOR THE THREE SERVICE CENTERS?

A. The cancellation of the Dashboard and Website Redesign is a perfect example of what can happen when forecasted capital expenditures for projects at the conceptual phase are included in projected rate base. Often, the projects get cancelled, costs are revised significantly, projects are delayed and the capital expenditures do not materialize to level forecasted. However, the Company still seeks to include those preliminary and tentative capital spending amounts in rate base and a return, plus recover depreciation expense and property taxes.

With regard to the two cancelled projects, I recommend that the Commission remove the capital expenditures of $5.7 million and the O&M expense of $600,000 from the 2021 projected test year in this rate case. The Commission should also reject the new Mobile App project at this time given the very conceptual nature of the project, and the inability for the parties to this rate case to fully assess the merits of the project at this late stage of the case.

2. Work Scheduling, Service Tracker and Streetlight Application

In Table 2 on page 30 of his direct testimony, Company witness Steven McLean presents seven IT projects. Three of the projects entail significant capital expenditures. The first project is the Online Work Scheduling with capital expenditures of $1,020,000 in 2021. The second project is the Service Tracker with capital expenditures of $2,040,000. The third project is the Streetlight Application with capital expenditures of $1,020,000. In total, the three projects would require approximately $4.1 million in capital expenditures in 2021. Two of the three projects also have a portion of the development cost allocated to the gas business for approximately $2.7 million in additional capital expenditures between 2020 and 2021.

In discovery, the Company was asked to identify the current phase of the projects, the total capital expenditures from inception to completions, the projects' cost estimate details, and other pertinent information to assess the reasonableness, timing and certainty of each of the projects. In response to discovery request AG-CE-1328, which is included in Exhibit AG-1.38, the Company provided some of the detailed information requested.

The Company disclosed that the three projects are still in the investment planning stage to discover the business requirements and possible technology options. In other words, the Company is still trying to determine what it needs and how it will accomplish its undefined requirements. These projects are again at a very conceptual and preliminary stage of development. The forecasted capital expenditures do not belong in rate base for the project test year. The timeline provided in the discovery response is not credible given that the Company has not yet defined its requirements and does not know what technology options it needs to implement.

I recommend that the Commission remove the $4,800,000 from the Company's 2021 capital spending forecast.

3. Bill Design, MIMO & Bill Financing Projects

In Table 3 on page 39 of his direct testimony, Company witness Steven McLean presents six IT projects. Four of the projects entail significant capital expenditures. The first project is the Bill Design and Delivery Transformation with capital expenditures of $5,209,551 and $926,970 of O&M expense in 2021. The second project is the Move

In/Move out project with capital expenditures of $1,105,813 and O&M expense of $46,215. The third project is the On-Bill Financing project with capital expenditures of $1,336,508 and $138,270 of O&M expense. The fourth project is the Move In/Move Out 3.0 project with capital with capital expenditures of $1,462,828 and $175,971 of O&M expense.

In total, the four projects would require approximately $9.1 million in capital expenditures and $1.3 million of O&M expense in 2021. Some of these projects would span over a two-year period with development costs also allocated to the gas business. In total, the four projects would entail approximately $25.7 million in capital expenditures from inception to completions and incremental annual O&M expense of more than $6.2 million.

In discovery, the Company was asked to identify the current phase of each of the projects, the total capital expenditures from inception to completions, the projects' cost estimate details, and other pertinent information to assess the reasonableness, timing and certainty of each of the projects. In response to discovery request AG-CE-1329, which is included in Exhibit AG-1.39, the Company provided some of the detailed information requested.

The Company disclosed that the four projects are still in the investment planning stage to discover the business requirements and possible technology options. In other words, like the projects discussed above, the Company is still trying to determine what it needs and how it will accomplish its undefined requirements. These projects are again at a very conceptual and preliminary stage of development. The forecasted capital expenditures do not belong in rate base for the project test year. The timeline provided in the discovery response is not credible given that the Company has not yet defined its requirements and does not know what technology options it needs to implement.

I recommend that the Commission remove the $9,114,000 from the Company's 2021 capital spending forecast and $1.3 million from the projected test year O&M expense.

4. 2019 Actual Information Technology Capital Expenditures

In discovery, the Company was asked to provide the actual capital expenditures incurred for the year 2019 in the Information Technology area. In response to discovery request AG-CE-1368, which is included in Exhibit AG-1.40, the Company reported that in 2019 it incurred $52,359,000 of actual capital expenditures in the IT area. This amount is $4,011,000 lower than the forecasted amount of $56,370,000 included in this rate case.

The Company should not be allowed to include costs in rate base which it did not spend. It would be unreasonable and unfair for customers to pay for the depreciation expense, property taxes and the return on capital investments that the Company did not actually incur in 2019. Furthermore, if these costs are not removed from rate base, it would give the Company an incentive to overstate its capital expenditures and rate base, because it would earn a return on investments it did not make. Therefore, I recommend that the Commission remove the $4,011,000 from rate base in this rate case.

G. Demand Response Program

In Exhibit A-12 (SQM-1), Schedule B-5.5, the Company shows total capital expenditures for the Demand Response (DR) program. For 2019 the Company forecasted $17.1 million, for 2020 it forecasted $10.9 million, and for 2021 it forecasted $8.9 million. Capital expenditures for 2018 were $6.7 million. In total, between 2018 and 2021, the Company will have incurred $43.6 million in capital expenditures on this program, with $36.9 million to be spent between 2019 and 2021.

In addition, on page 5 of Exhibit A-75 (SQM-2), the Company forecasted O&M expense for the DR program of $34.7 million for the projected test year, with expenses ranging between $6.9 million in 2018 and $26.7 million in 2020. In total, for the four years from 2018 to 2021, the Company will have incurred $81.0 million during the four years from 2018 to 2021, with $74.1 million to be incurred between 2019 and 2021.

On a combined basis, the DR program will entail $124.6 million of capital and O&M spending during the four-year period from 2018 to 2021, with $111.0 million occurring between 2019 and 2021.

As a result of this spending, the Company achieved DR capacity reductions of 107 MW in 2018 and 173 MW in 2019. With the proposed spending level, it is now forecasting that it will achieve DR capacity reductions of 288 MW in 2020 and 389 MW in 2021. Exhibit AG-1.41, includes the discovery response and attachment showing the historical and projected spending on the DR program and the capacity reductions achieved and projected for 2020 and 2021. Mr. McLean's direct testimony beginning on page 63 provides additional details on the DR program.

Q. **HOW DO THE SPENDING AMOUNTS AND DR CAPACITY REDUCTIONS COMPARE TO THE LEVELS FORECASTED BY THE COMPANY IN THE IRP IN CASE NO. U-20165?**

A. In the Company's Integrated Resources Plan (IRP), the Company proposed $37.2 million in capital spending between 2019 and 2021, which is similar to the $36.9 million forecasted in this rate case for the same time period. However, on the O&M expense side, the Company forecasted $38.3 million in Case No. U-20165 for the three years between 2019 and 2021, and in this rate case, it now forecasts O&M expense of $74.1 million for the same three years. This is a 93% increase in program costs in about 20 months between the submission of the IRP in mid-2018 and the filing of this rate case in February 2020.

More concerning is the fact that the DR capacity reductions forecasted in the IRP have not materialized and are not forecasted to occur during the two upcoming years in 2020 and 2021. In the IRP, the Company forecasted that it would achieve DR capacity reductions of 369 MW in 2019, 451 in 2020 and 531 MW in 2021. In comparison, it only achieved 173 MW in 2019, which is a 53% shortfall, and now forecasts it will be able to achieve only 288 MW in 2020 and 389 MW in 2021. The 2020 and 2021 projections are a shortfall of 36% and 27%, respectively from the levels forecasted in the IRP. Exhibit AG-1.41

includes also the schedules from the IRP with the forecasted spending and capacity reductions.

Q. **WHAT IS YOUR ASSESSMENT OF THE DR PROGRAM PROPOSED BY THE COMPANY IN THIS RATE CASE?**

A. Although the Attorney General supported the DR program in Case No. U-20165 based on the Company's forecasts and representations as to what the program could achieve and the benefits it would provide customers, the level of benefits appears to be in doubt based on the information presented in this rate case.

On a combined basis, between capital spending and O&M expense, the Company is now forecasting total spending on the DR program of $111.0 million for the three years 2019 to 2021. In comparison, the Company had forecasted total spending of $75.5 million in the IRP. Therefore, the Company will be spending 47% more to achieve a lower volume of DR capacity reduction. As stated earlier, the Company now plans to achieve between 27% to 53% fewer MW capacity reductions during the three-year period. This is a disastrous outcome for customers.

Q. **WHAT ARE YOUR RECOMMENDATIONS?**

A. The biggest area of concern with the DR program is the O&M spending level. In the IRP, the Company forecasted $15,761,000 in O&M expense for 2021. It now forecasts $34,682,000 in O&M expense for the 2021 projected test year. The difference is

$18,921,000, or more than 100% from the initial forecast in the IRP. The Company has not provided any justification for the significant increase in expense and the shortfall in achieving the planned capacity reductions forecasted in the IRP.

I recommend that the Commission disallow the difference of $18,921,000 of O&M expense from the revenue requirement in this rate case. Furthermore, I recommend that the Commission direct the Company to reassess the true costs and benefits of the DR program and take appropriate steps to reduce expenses and increase the DR capacity reductions to levels commensurate to those presented in the IRP. The Company should present the reassessment of whether the DR program is still beneficial and at what level of expenditures in the next DR program reconciliation case, rate case of IRP, whichever occurs first.

Q. **DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS?**

A. Yes. On page 74 of his direct testimony, Mr. McLean proposed to begin a pilot program at a cost of $3.2 million to reduce peak demand from water heaters, pool pumps and hot tubs. Given the significant cost overruns with the existing DR program, the Commission should not approve any additional pilot programs and expansion of the program until the Company provides a full reassessment of the current program.

Therefore, I recommend that the Commission remove the $3.2 million from capital expenditures for the projected test year.

Furthermore, to the degree that the Company currently earns incentive payments under the DR program, the Commission should suspend any such payments until a true assessment of the benefits of the DR program is completed and approved by the Commission.

H. Capital Expenditures - Summary

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING THE LEVEL OF CAPITAL EXPENDITURES?

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 and unnecessary.

Summary of AG Disallowed Capital Expenditures	
	Amount (millions)
Distribution Plant	$ 227.9
Power Generation	62.6
Information Technology	22.9
Operations Support	58.4
Fleet Services	40.0
Demand Response Program	3.2
Total	**$ 415.0**

Based on my analysis and the information presented in my testimony above, I recommend that the Commission reduce the Company's proposed capital expenditures by $415 million and reduce average rate base by $253.4 million, as shown in Exhibit AG-1.42. The resulting effect of the lower rate base from the reduction in capital expenditures is a reduction in the revenue deficiency of $18.7 million.

IV. Deferred Capital Spending Recovery Mechanism

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSALS WITH REGARD TO THE DEFERRED CAPITAL SPENDING RECOVERY MECHANISM.

A. There are two issues with the Deferred Capital Spending Recovery (DCSR) mechanism. First, the Company seeks to recover the revenue requirement for both 2019 and 2020 for the DCSR mechanism approved by the Commission in the settlement of Case No. U-20134. Second, the Company seeks to continue the same mechanism for the 2021 projected test year capital expenditures that would be established in this rate case

With regard to the first issue, beginning on page 31 of her direct testimony, Company witness Heidi Myers argues that the Company should be permitted to recover the revenue requirement for both 2019 and 2020, because the Company was not able to file a rate case until after January 1, 2020. The revenue requirement for 2019 is $6.3 million, as calculated by Ms. Myers. She proposes to double the amount of $12.6 million to include also the 2020 revenue requirement, using the 2019 amount as a proxy for 2020.

Paragraph 8 of the settlement agreement is very clear that the deferred accounting mechanism applied only to the 2019 revenue requirement for the excess capital expenditures incurred in that year. There is no mention in the settlement for the Company to also recover the revenue requirement for the subsequent year in 2020.

The fact that the Company agreed to not file a rate case until after January 1, 2020 is something that the Company needs to deal with in managing its business. The parties to the agreement expected that this mechanism would be a one-year adjustment to supplement the agree to revenue deficiency in Case No. U-20134. The settlement agreement was as part of the give and take of negotiations on several issues, and the parties to the settlement agreement certainly did not anticipate that the Company would want to recover also the 2020 revenue requirement. If they had agreed to such an arrangement, it would have been written in the settlement agreement.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission reject the Company's proposal to recover the 2020 revenue requirement of $6.3 million for 2020.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO CONTINUE THE DCSR MECHANISM FOR THE 2021 PROJECTED TEST YEAR.

A. Beginning on page 3 of his direct testimony, Company witness Daniel Harry proposes the same DCSR mechanism for 2021 that was included in the settlement agreement in Case No. U-20134.

Mr. Harry's testimony states that the mechanism would capture the revenue requirement of capital spending for Distribution New Business, Demand Failures and Asset Relocation <u>above what is included in rates</u> should the Commission not approve the full amount of capital spending for those three categories of capital programs for 2021. However, that statement does not limit the calculation of the deferred revenue requirement to only the difference between what the Company proposed for 2021 and the level approved by the Commission and reflected in rates. As stated by Mr. Harry, the deferred revenue requirement is not limited to any spending level.

Mr. Harry goes on to explain how the Company would calculate the deferred revenue requirement to be recovered in the next rate case. The revenue requirement would be calculated as if the excess spending amount had been charged to rate base. The deferred revenue requirement would include the return on the investment at the Company's approved rate of return, plus depreciation and property taxes. In other words, the company wants to be made whole for any proposed capital spending disallowed by the Commission in this rate case for New Business, Demand Failures and Asset Relocations, plus potentially any additional amounts spent above the proposed level.

Mr. Harry also states that any balance in the regulatory asset associated with the DCSR mechanism would accrue interest at the Company's short-term borrowing rate.

Q. WHAT IS YOUR ASSESSMENT OF THE PROPOSED DCSR MECHANISM?

A. The proposed DCSR mechanism should not be approved by the Commission. Such a mechanism would upend the normal regulatory model where the Commission reviews the evidence in a rate case and determines what level of capital spending has been justified to include in rate base and in the calculation of new rates for the Company. Although the parties to Case No. U-20134 agreed to a similar mechanism in the settlement of that case, it was the result of negotiations and give-and-take on several issues. The settlement agreement should not establish a precedent event that should apply to this rate case.

In Exhibit A-40 (RTB-1) in this rate case, the Company shows the capital expenditures that were set in the settlement agreement in Case No. U-20134 for the DCSR mechanism and the actual amount spent in 2019. The forecasted amount was $205 million. The actual amount spent by the Company was $311 million, or a 52% increase from the forecast amount. This is a perfect example of what happens when the Company is given an open check book to spend without any limits, which are normally set in base rates, and gets to recover all excess spending above a set threshold. The Commission should not encourage such excess spending by approving another DCSR in this rate case.

The Company has proposed nearly $314 million in capital spending in this rate case for New Business, Demand Failures and Asset Relocations for the 2021 test year. If the Commission does not approve a portion of the $314 million, it is because the Company did not provide sufficient evidence that the proposed spending level would be achieved. By calculating the revenue requirement on amounts not approved, the DCSR mechanism would allow the Company to recover costs the Commission determined were not appropriate for inclusion in rates for whatever reasons.

Approval of the DCSR mechanism would set a bad regulatory policy precedent that could be exploited by the Company and other Michigan utilities under the Commission's jurisdiction. What may appear to be a small exception in this case could grow to include other categories of capital spending that the Company or other utilities would argue is outside of their control. We have seen this phenomenon occur with various Investment Recovery Mechanisms.

It should be clear that the ultimate objective of the Company in proposing this mechanism is to have unbridled authority to spend at the levels that it desires and not experience any regulatory lag in recovering the return on investment, depreciation and property taxes. However, it is that very concept of regulatory lag which imposes a degree of financial discipline on utilities to undertake only the most essential, reasonable and prudent projects.

The Company's argument that it has no control over capital spending for New Business, Demand Failures and Asset Relocations is a red herring. First of all, New Business projects usually have long lead times and, more importantly, should bring new sales and revenue which the Company retains until the next rate case. The additional revenue should offset at least some if not most of the revenue requirement while the Company is between rate cases.

Second, as the Company has been filing general rate cases almost annually, any shortfall in recovering the costs associated with actual spending levels above the level reflected in rates is short lived. The Company has been earning returns at above the authorized ROE rate for several years. There is no compelling reason to implement a new cost recovery mechanism. The Company is not in financial distress and is not significantly under-earning due to regulatory lag. If the Company believes that it is suffering from significant delayed recovery of costs from excessive capital spending, the solution is to better manage and control capital spending. The solution is not for the Commission to approve a mechanism that would encourage additional capital spending

Q. WHAT IS YOU RECOMMENDATION?

A. I recommend that the Commission reject the Company's proposal to implement the DCSR mechanism.

V. Cost of Capital

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

A. I recommend that the capital structure shown on page 1 of Exhibit AG-1.43 be used in this case. The first three lines show the projected long-term debt, preferred equity and common equity capital of the Company, which represents the permanent capital structure for the test period ending December 2021. The capital balances in this exhibit reflect the amounts shown in Company Exhibit A-14 (MRB-1), Schedule D1, with an adjustment to rebalance the capital structure. The long-term debt component in Exhibit AG-1.43 has been increased by $432 million and the common equity component has been reduced by the same amount. The result is a capital structure with 50% of common equity and 50% of debt and preferred stock.

Q. **WHY DID YOU INCREASE LONG TERM DEBT BY $432 MILLION AND OFFSET THIS CHANGE WITH LOWER COMMON EQUITY OF $432 MILLION?**

A. The Company has proposed a permanent capital structure with a common equity component of 52.50%. While this percentage is slightly less than the 2018 historical test year percent of 53.46%[15], there are other factors to consider. These other factors include (1) the Commission's directive in the Company's electric rate case U-17990 that moving to a 50/50 capital structure is appropriate in the absence of evidence suggesting otherwise; (2) the Company's practice of funding a significant part of its equity contributions with long term debt issued at the parent company level; (3) the Company's unsupported position that a higher equity cushion is needed to maintain its credit ratings on long-term debt; and (4) the fact that the common equity ratio of the peer group, used to assess the cost of common equity in this case, is approximately 45%.[16]

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[15] Exhibit A-14 (MRB-2), Schedule D1a, page 1.

[16] Exhibit AG-1.47 shows that the peer group average equity ratio for each peer company and the average for the group, which is 45.5%. However, even after excluding First Energy, which has a low equity ratio, the average for the group is still below 50% at 47.2%.

Q. PLEASE EXPLAIN YOUR ASSESSMENT OF THE COMMISSION'S DIRECTIVE TO THE COMPANY TO REBALANCE ITS CAPITAL STRUCTURE TO AN EQUAL AMOUNT OF DEBT AND EQUITY CAPITAL.

A. The Commission in its order of February 17, 2017 in Case No. U-17990 stated:

> The Commission expects that Consumers will have arrived at, or will present a strategy to return to, a balanced structure within the five-year infrastructure plan time period. If Consumers is unable to do so, a more complete analysis should be included to explain why such a result is reasonable and prudent.

Company witness Andrew Denato discussed this matter on page 9 of his direct testimony in Case No. U-18424, which was the Company's 2018 gas rate case, and explained that the Company's common equity ratio should decrease as certain purchase power agreements ("PPAs") for electricity purchases expire. Mr. Denato further explained that it is the Company's plan to reduce its common equity ratio to 52.5% in 2018, 52.0% in 2019, 51.5% in 2020; and by a half of a percentage point in each year until the 50% ratio is achieved in 2023.

Additionally, on page 9 of his testimony in Case No. U-18424, Mr. Denato stated that "…as the Company's significant capital investment program decelerates to more normal levels, the need for an equity ratio slightly higher than 50% will be less critical". This was the Company's position in October 2017 which precedes the filing of this case in December 2019 by approximately two years.[17]

[17] In rebuttal testimony in Case No. U-18424, Mr. Denato raised the issue that the 2017 Tax Cut and Jobs Act would result in a deterioration in cash flow to debt coverage ratios, which made the Company's

In contrast, in this rate case and in cases Nos. U-20134, U-20650 and U-20322 (the Company's last electric case and the two most recent gas rate cases), the Company's position has changed, and the previous commitment has been tossed aside. On pages 10 through 25 of his direct testimony in this case, Mr. Bleckman explains that the TCJA makes a common equity ratio of 52.5% mandatory for the foreseeable future. He also points to other reasons, such as the financing required for the Company's planned infrastructure upgrade, the effect of PPAs, and maintaining certain cash flow ratios in support of the Company's credit ratings. It is noteworthy to point out that in his direct testimony, Mr. Bleckman does not address either the expiring Power PPAs nor the deceleration in capital expenditures, which were major considerations in Mr. Denato's proposal in Case No. U-18424.

Instead, as discussed in my testimony in Case U-20322, the Company has communicated to investors and securities analysts that because of the pass-through to customers of lower taxes from the TCJA, it has "headroom" to increase capital expenditures at an even higher level.[18] This information clearly contradicts the view that it needs a higher equity ratio as a result of the TCJA.

The additional debt to fund additional capital expenditures, which the Company has stated are now opportunistically possible due to the TCJA, is likely to be the real issue for rating

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commitment to reach a 50/50 balanced capital structure no longer achievable. However, in cross examination in that case, Mr. Denato could not provide any evidence to support his claim. [MPSC Case No. Transcript Volume 3 at pages 1142-1144].

[18] See Exhibit AG-1.52.

agencies when assessing the Company's credit ratios. The rating agencies have frequently expressed concerns with the Company's high level of capital expenditures, which require more debt capital to finance them. A better option to increasing the equity ratio would be for the Company to decrease capital expenditures and issue less debt if it is concerned with its cash flow to debt coverage ratios. Rating agencies certainly would welcome lower capital expenditures and fewer new debt issuances.

If the Company's capital program is not scaled down and instead is further escalated, the resulting incremental debt will weaken the same cash flow ratios with which the Company is concerned.

With regard to Mr. Bleckman's discussion of PPAs, the Commission should disregard the entire argument about PPAs being a factor to justify a higher equity ratio. Consumers Energy is not unique in using PPAs to buy power. Most, if not all, of the Company's peer utilities buy power under PPAs. Thus, there is no basis to the argument that Consumers Energy should carry higher common equity capital to support these contracts. Furthermore, in Case No. U-20165, the Company's most recent Integrated Resources Plan, the Commission approved a Financial Compensation mechanism that allows the Company to recover the imputed cost of equity capital forfeited pertaining to new PPAs.

In its September 26, 2019 order in the Company's last gas rate case No. U-20322, the Commission decided to set the common equity ratio at 52.05%, as recommended by the Commission Staff. However, the Commission noted on page 54 of the order that the

Staff's recommendation was based in part on "…the Commission's desire to see the Company move toward a 50/50 capital structure."

Q. PLEASE DISCUSS THE RATING AGENCY ADJUSTED FFO ANALYSIS SHOWN ON PAGE 15 OF MR. BLECKMAN'S DIRECT TESTIMONY.

A. The chart and related testimony beginning page 14 presenting the cash flow to debt coverage ratios is inaccurate and highly misleading. Mr. Bleckman's chart suggests that based on a 52.05% common equity ratio and a 9.9% ROE (assigned in Case No. U-20322), Consumers Energy would face a credit rating downgrade from a credit rating of "A" to the "Baa" category by Moody's Investor Service (Moody's). This is not true. I will discuss this matter in more detail below and show why Mr. Bleckman's analysis and conclusions are incorrect. It is also important to point out that the current senior secured credit rating by Moody's is "Aa3", which is two notches above the "A" rating assigned by Standard & Poor's (S&P) and one notch above the "A+" rating assigned by Fitch Investor Service (Fitch).

Additionally, the chart shows that the Company would move from the "Intermediate Risk" category to the "Significant Risk" category according to the S&P credit criteria. While this change may sound ominous, it does not mean that such a change in the risk profile will occur or that S&P would downgrade the Company's credit rating.

Q. WHAT IS S&P'S RECENT CREDIT ANNOUNCEMENT ON CONSUMERS ENERGY'S CREDIT PROFILE?

A. According to Exhibit A-24 (MRB-8), the Company's senior secured debt is rated as "A" by S&P. Furthermore, on page 3 of its January 29, 2020 report on Consumers Energy, S&P made the following statement in the section "Downside Scenario".

> We could lower our rating on Consumers Energy if its stand-alone financial measures weaken such that its FFO to debt weakens to consistently below 15%. We could also lower our rating on Consumers Energy if we lower our rating on its parent, CMS Energy.[19]

Page 3 of the report also shows the 2018 FFO to debt coverage ratio for Consumers Energy at 21.4%. Even Mr. Bleckman's own Exhibit A-27 (MRB-11) shows a coverage ratio of 18.6% after adjusting 2018 results for the effects of the TCJA and the ROE and common equity parameters from Case No. U-20322. The 18.6% coverage ratio for 2018 is well above the 15% threshold referenced by S&P in the section of the report quoted above. Accordingly, there is no risk of a S&P downgrade of the Company's debt due to the TCJA cash flow changes as implied by Mr. Bleckman.

Q. WHAT IS MOODY'S LATEST VIEW OF CONSUMERS ENERGY'S CREDIT POSITION?

A. In its June 19, 2019 report, Moody's stated that a downgrade could be considered if the regulatory environment in Michigan becomes less constructive and if financial metrics deteriorate "…such as CFO pre-W/C falling to below 20% or if parent [company] debt

[19] Standard & Poor's January 29; 2020 report provided in discovery response AG-CE-587 included in Exhibit AG-1.53.

increases.…"[20] The issue of parent company debt is addressed later in my testimony. Although remote, even if a one notch downgrade by Moody's were to occur, the credit rating would still be one notch above S&P's credit rating and at par with Fitch's credit rating. Therefore, Mr. Bleckman's prediction of a downgrade to "Baa" level, which would be a four-notch drop, is nothing more than speculation to increase the amount of equity capital in the capital structure in order to increase its revenue requirement and the Company's earnings.

Q. IN EXHIBIT A-27 (MRB-11), MR. BLECKMAN SHOWS A 2018 CFO PRE-W/C TO DEBT RATIO OF 19.1% AFTER SEVERAL ADJUSTMENTS. SHOULD THE COMMISSION BE CONCERNED WITH THIS OUTCOME AND THAT IT MIGHT LEAD TO A DOWNGRADE OF THE COMPANY'S CREDIT?

A. No. The Company's analysis is neither complete nor convincing. Mr. Bleckman arrives at the 19.1% coverage ratio for 2018 by making adjustments for the TCJA in column (b) on lines 4 and 5 even though the TCJA was in effect for all of 2018. These adjustments are inappropriate. Through discovery in Case U-20650, the Company was asked to explain why these adjustments were necessary. The response did not provide any useful information.[21]

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[20] Moody's report (page 2) "Factors that could lead to a downgrade" provided by CECo in response to DR AG-CE-587 Attachment. See Exhibit AG-1.53.
[21] CECo response in U-20650 to DR AG-CE-101.

If these adjustments are excluded, the coverage ratio would be 21.1%, which is above the 20.0% coverage ratio threshold.

Moreover, page 9 of Moody's June 19, 2019 report shows the CFO Pre-W/C to Debt ratio at 22.3% for the 12 months ended March 2019, which further supports the conclusion that the Company is exceeding the 20% coverage threshold more than a year after the TJCA went into effect.

Q. DID YOU CALCULATE THE IMPACT ON THE CASH FLOW TO DEBT COVERAGE RATIOS BASED ON A 50% EQUITY RATIO IN THE COMPANY'S CAPITAL STRUCTURE AND AN AUTHORIZED ROE OF 9.50%?

A. Yes. In Exhibit AG-1.44, I calculated the Company's key cash flow to debt coverage ratios for 2017 adjusted for the TCJA, and the ROE and Common Equity ratio levels advocated in the Attorney General's case. I utilized both the S&P and Moody's coverage ratio results for 2017 and adjusted them for the TCJA cash flow changes, the ROE rate of 9.50%, and a 50% common equity capital ratio. I chose 2017 because the Company's 2018 derived results are unreliable and the 2017 data which was presented by the Company in Case U-20650 in Exhibit A-26 is more reliable. It is also noteworthy that the Company could have presented ratio results for 2019 in this case, but it chose not to do so.

In Exhibit AG-1.44, I started with the actual data and coverage ratios as determined by S&P and Moody's for 2017. The beginning coverage ratio is 23.5% for S&P and 26.9% for Moody's. After including the TCJA adjustments developed by witness Bleckman, the coverage ratios decline to 19.4% for S&P and 22.4% for Moody's. Further adjusting these ratios for 2017 by adding in $240 million of long-term debt due to less common equity to achieve an equity ratio of 50% and adjusting the ROE to 9.5%, the cash flow coverage ratios drop slightly to 18.3% for S&P and 21.1% for Moody's. As apparent from reviewing Exhibit AG-1.44, the Company would still have exceeded the minimum cash flow to debt coverage ratios of both rating agencies in 2017 by comfortable margins even after adjusting for the TCJA, a 9.5% ROE, and a 50% common equity ratio.

The Commission should not be swayed from its stated objective of requiring the Company to present a balanced capital structure of 50% common equity and 50% debt and preferred stock capital.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE CASH FLOW TO DEBT COVERAGE RATIOS THAT THE COMPANY USES AS JUSTIFICATION FOR PROPOSING A 52.5% EQUITY RATIO?

A. The premise put forth by Mr. Bleckman that the Company needs an equity ratio of 52.5% has no factual basis and is meritless. As I have shown in Exhibit AG-1.44, the Company has ample room in cash flow to debt coverage ratios to sustain a 50% common equity ratio and a ROE rate of 9.50%, and still maintain the coverage ratios above the minimum ratios set by S&P and Moody's in order to avoid a downgrade.

We should again keep in mind that the Company's credit rating of "Aa3" by Moody's is two notches higher than the "A" debt rating assigned by S&P and the main reason for the higher minimum coverage ratio required by Moody's. It is also important to point out again that the amount of debt on the Company's books is a direct result of the aggressive and growing capital expenditures program. The Company can improve the cash flow to debt coverage ratios by reducing debt with a more moderate capital expenditures program.

Therefore, the Company's argument that it needs to have a 52.5% equity ratio to avoid a potential downgrade because the cash flow to debt coverage ratios have weakened due to the enactment of the TCJA is a red herring. The real motivation to increase the amount of common equity in the capital structure is to expand the base on which the Company can get a greater return on investment and increase its earnings. The Commission should be mindful of this motivation and should reject the Company's recommendation for a 52.5% common equity ratio. Instead, the Commission should adopt the recommendation for a balanced capital structure of 50% common equity and 50% long-term debt and preferred stock.

Q. **YOU STATED EARLIER THAT THE COMMON EQUITY CAPITAL INFUSIONS INTO CONSUMERS ENERGY BY THE PARENT COMPANY ARE BEING FUNDED TO SOME EXTENT BY LONG TERM DEBT. PLEASE EXPLAIN.**

A. There are several issues in the financial transactions between Consumers Energy and its parent company, CMS Energy ("CMS"), which cannot be ignored when analyzing the Company's proposed capital structure. First, CMS can make the Company's common equity ratio whatever it wants. The same executive management that runs CMS Energy also operates the Company. Management can direct at any time how much in capital it wants to inject into the Company from the parent company and call it equity capital. In fact, it has done just that over the years. In response to a discovery request, the Company has stated that the injection of common equity from CMS Energy is at the discretion of management with no approval from the Board of Directors.[22] Such freedom to call for equity capital would not exist if Consumers Energy itself was a publicly-traded company.

Over the five years 2015 to 2019, Consumers Energy's Common Equity has increased by $2.5 billion from $5.2 billion to $7.7 billion. An analysis of the Company's financial statements filed with the Securities and Exchange Commission shows that the $2.5 billion increase is due to the following factors.

Consumers Energy		
Common Equity Change Five Years (2015 - 2019)		**Billions**
Net Income of Consumers Energy	$	3.3
Dividends Paid to CMS		(2.6)
New CMS Investment in Consumers Energy		1.8
Total Change in Common Equity	**$**	**2.5**

My analysis of CMS Energy's financial statements shows that approximately $1.0 billion or 56% of the $1.8 billion of so-called equity investments by CMS to Consumers Energy

[22] CECo response to discovery request U-18322-AG-CE-439.

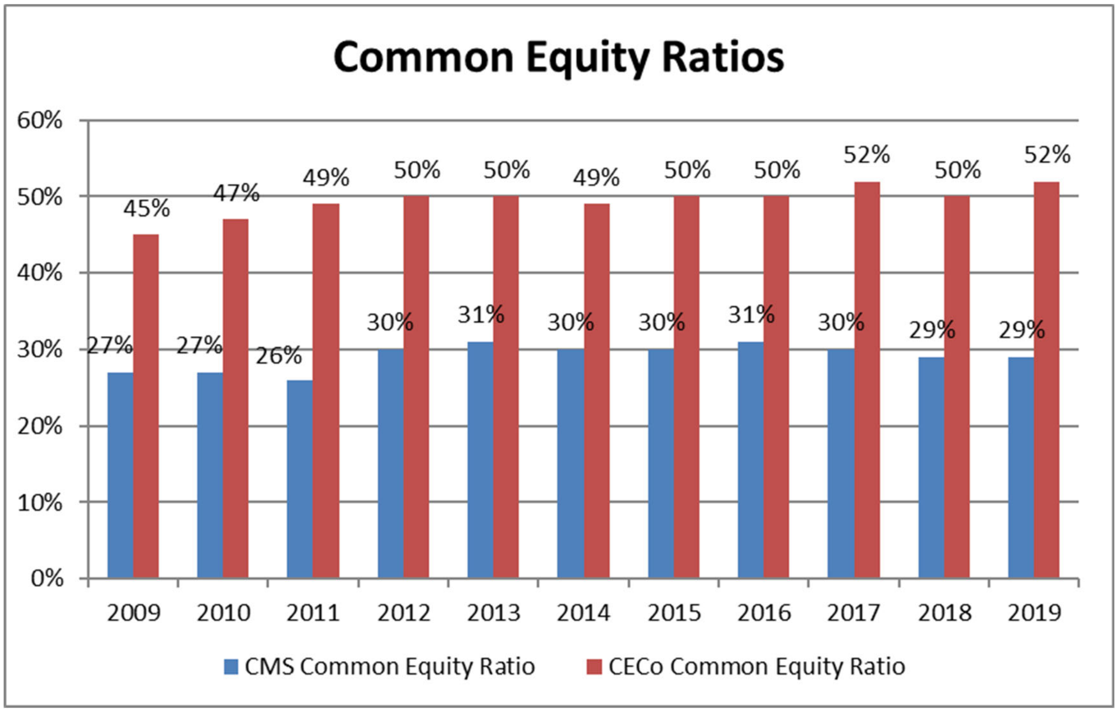
from 2015 to 2019 was new debt issued at the parent company and injected as equity capital in the utility. The table below shows this phenomenon very clearly.

CMS Energy		
CMS Funds Available to Invest in Consumers Energy		**Billions**
Dividends from Consumers Energy	$	2.6
Less: Dividends to CMS Shareholders		(1.9)
Less: Other CMS Parent Co. Interest & Other		(0.4)
Sub Total		0.3
Increase in Parent Company Debt		1.0
Other - CMS Equity Issued & Other		0.5
Funds For New CMS Investment in Consumers Energy	**$**	**1.8**

Second, to further support my point, CMS Energy is a frequent issuer of long-term debt in the capital markets. Over the last five years, CMS parent-only debt has increased from $2.4 billion at year end 2014 to $3.5 billion at year end 2019.[23]

The following chart displays the gap in equity capital between Consumers Energy and CMS over the years 2009 to 2019. While cash raised from the issuance of long-term debt at CMS is not immediately injected into Consumers Energy, it is nonetheless being utilized in part to fund CMS's so-called equity infusions into CECo.

[23] From SEC filings on Form 10-K for the years ended 2014 and 2019.



It is important to remember that nearly 100% of CMS' assets and earnings come from Consumers Energy. Therefore, from a practical operating standpoint, CMS and Consumers Energy are one and the same.

My analysis clearly shows that CMS is using a form of double leverage by using debt capital to make its equity infusions into Consumers Energy. Although a strong argument could be made that the common equity capital of the Company should be less than 50% given the evidence I have presented, the Commission certainly should not permit a capital structure with common equity capital above 50%.

The excessive debt and low common equity ratio at CMS (29% at year-end 2019 and unchanged from year-end 2018) are a continuing concern for the rating agencies when assessing the debt rating of Consumers Energy. For example, in its June 20, 2018 credit update report on the Company, Moody's stated "An increase in parent level debt leading to a decline in the credit quality of CMS" as a potential factor that could lead to a downgrade of the Company.[24] Similarly, page 2 of the Moody's report issued a year later on June 19, 2019 contains a substantially similar comment.[25] Yet, CMS continues to further leverage its balance sheet at the parent company level to fund equity contributions into Consumers Energy.

From the statements in Moody's credit reports and similar concerns expressed by other rating agencies, it appears that the debt-laden capital structure of CMS has contributed to a lower debt rating than the Company could have achieved if CMS was capitalized with more equity capital. The result has been higher interest costs for customers. Partially to compensate for this significant leverage at CMS, the Company now wants a higher equity ratio in the capital structure that will further increase costs to customers.

Q. IF THE COMPANY WERE TO BE DOWNGRADED ONE NOTCH BY MOODY'S FROM "AA3: TO "A1" DUE TO FURTHER LEVERAGING OF THE CMS CAPITAL STRUCTURE OR FOR OTHER REASONS, WHAT WOULD BE THE APPROXIMATE HIGHER COST THAT THE COMPANY WOULD INCUR?

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[24] See Exhibit AG-1.53, Moody's Report of June 20, 2018, page 2. attachment to Case U-20322 Staff Audit Request #11.
[25] See Exhibit AG-1.53, Moody's Report of June 19, 2019, page 2 attachment to AG-CE-587 under "Factors that could lead to a downgrade"

A. Based on new long-term debt issued during the 18 months ended September 2019, the additional cost could be as much as 10 basis points or one tenth of one percent. This means that the additional cost for a new 30-year $500 million bond issue could increase to $500,000 per year. This cost is dwarfed by the higher cost to customers from carrying a higher common equity balance at the 52.5% level proposed by the Company. As discussed later in my testimony, the increase in the revenue requirement of having a common equity ratio of 52.5% versus a 50% ratio is $24.6 million annually.

Q. MR. WEHNER DISCUSSES THE ISSUE OF CAPITAL STRUCTURE ON PAGES 22-23 OF HIS TESTIMONY AND SPONSORS EXHIBIT A-115 (TAW-2) SHOWING THAT THE 52.5% COMMON EQUITY RATIO AND 10.0% ROE MAY BE INADEQUATE TO MAINTAIN THE COMPANY'S CREDIT RATINGS. WHAT IS YOUR ASSESSMENT?

A. The equation shown in Exhibit A-115 is defective and too simplistic for two reasons. First, there is no provision in his equation for deferred income taxes. I will point out that deferred income taxes are projected to increase from $3.1 billion in the historical 2018 period to $3.7 billion in the projected test year. Yet, witness Wehner ignores this key source of funds in his equation. Second, his depreciation component of 3.9% is a gross plant depreciation rate and as such is understated and should use a higher rate for these purposes. It is the Company's net plant (not its gross plant) that is being financed with debt and equity. Adjusting this rate upward to 5.2% would be more reflective of the true cash flow benefit from depreciation expense.[26] Witness Wehner's equation is unreliable for evaluating the Company's key cash flow ratios used by the rating agencies for the reasons noted above. As such, the Commission should give no weight to his testimony and his exhibit related to this matter.

Q. **YOU STATED THAT THE AVERAGE COMMON EQUITY RATIO OF THE PEER GROUP USED TO ASSESS THE COST OF COMMON EQUITY IS APPROXIMATELY 45%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE COMMON EQUITY RATIO FOR THE COMPANY.**

A. As shown in Exhibit AG-1.47, the average common equity ratio of the peer company group for 2019 was 45.5%. Even if we exclude the lower equity ratio of First Energy Corporation, the average common equity ratio of the remaining 11 companies is 47.2%. The cost of equity for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure. Thus, it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible, in order to have consistency with the cost of equity capital derived from those peer group companies. The Company's proposed common equity capital ratio of 52.5% creates a disconnect that is not acceptable and is also more costly to customers.

[26] As an indication that the 3.9% rate is understated, CECo's filed rate base in this case and Case No. U-20650 is $19.2 billion. Depreciation expense from the two cases is approximately $1.0 billion. Dividing the $1.0 billion by the $19.2 billion rate base equals 5.2%.

Q. WHAT IS THE REVENUE REQUIREMENT SAVINGS RELATED TO A LOWER COMMON EQUITY RATIO OF 50% IN COMPARISON TO THE COMPANY'S PROPOSED EQUITY RATIO OF 52.5%?

A. The difference is approximately $24.6 million annually. This reflects (a) the difference between the pre-tax cost of common equity of approximately 14.1% versus the cost of long-term debt of 3.95%; (b) the Company's proposed rate base of approximately $11.8 billion; and (c) the percentage of total capital being shifted from common equity to long term debt.

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

A. No. I have utilized the other capital balances sponsored by witness Bleckman on his Exhibit A-14 (MRB-1), Schedule D1.

Q. **WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL DO YOU RECOMMEND IN THIS CASE?**

A. I recommend an overall return on capital of 5.50%, which includes a return on common equity of 9.50%, as shown in Exhibit AG-1.43. Even though the average ROE calculated under the three methods discussed below is approximately 8.44%, I have used a 9.50% ROE rate to calculate the overall cost of capital for reasons I will explain later in my testimony.

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

A. For the long-term debt cost rate, I used a rate of 3.84%. To develop this rate, I started with the 3.95% cost rate proposed by Company witness Bleckman which included new issuances in 2020 at 3.875%. The Company actually issued $875 million of new debt in the first quarter of 2020 at a composite rate of 2.79%, which is lower by approximately one full percentage point than what witness Bleckman originally anticipated. Factoring in these lower cost debt issues reduces the cost for long term debt from 3.95% to 3.84% and saves electric customers $4.6 million annually.

Q. WHAT COST RATE DID YOU UTILIZE FOR PREFERRED STOCK?

A. For CECo's preferred stock, I used a 4.5% rate, consistent with the rate recommended by Company witness Bleckman.

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 used the cost rates recommended by witness Bleckman. Cost rates for JDITC reflect those rates I used for the permanent capital sources.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-1.43.

A. To develop the overall cost of capital on line 12, 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 5.50%.

Regarding the pretax weighted cost of capital on line 12, column (h), I have multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income and other taxes paid by CECo for calculation of the pretax weighted cost of 6.83% in column (h).

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

A. A utility company is entitled to a fair return that will allow it to attract capital and be sufficient to assure investors of its financial soundness. In its opinion in Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia (the “Bluefield Case”) 262 U.S. 679 (1923), the United States Supreme Court indicated that:

> *“A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that being made at the same time…on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under*

efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties…"

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

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON EQUITY IN EXHIBIT AG-1.45.

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 assessing this cost. These are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM) and the Utility Risk Premium approach.

While Exhibit AG-1.45 shows an average ROE of 8.44% from the three methodologies, I recommend an allowed rate of return on equity of 9.50% for the reasons explained later in this section of my testimony. In connection with these methods for determining the cost of common equity, I have considered the cost of common equity for a proxy group of peer companies.

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

A. To develop an appropriate peer group, I started with the 37 electric utility companies followed by the Value Line Investment Survey in its "Electric Utility Industry" sections. I have removed the smaller electric utilities (annual revenues under $1.5 billion) and the largest electric utilities (annual revenues over $16.5 billion). This results in a narrowing of the group from 37 down to 23 electric utilities. I then further excluded companies with foreign investment (Fortis, PPL and Sempra), and companies involved in merger and acquisition activity or reorganization efforts (Eversource, Centerpoint and Evergy), as well as companies with no projected dividend growth (AVANGRID) and companies with a recent or projected earnings fall-off. Finally, I eliminated Hawaiian Electric (credit ratings unknown) and CMS, as is customary. Exhibit AG-1.51 shows the companies reviewed and selected for my peer group.

The result is the group of 12 companies shown in Exhibit AG-1.46, all of which have growing earnings and dividends.

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

A. My peer group is the same size (12 companies) as the one sponsored by Company witness Wehner with also 12 companies. However, my peer group is more reflective of the electric business of Consumers Energy than the group of companies selected by the Company.

First, it should be noted that Mr. Wehner has included NiSource. Value Line classifies this Company as a gas utility and 87% of its customers are gas customers. Second, Mr.

Wehner included Dominion Energy in his peer group. Following its 2019 merger with SCANA, Dominion Energy is now a substantially larger company than Consumers Energy. Also, Dominion experienced a drop in earnings recently with 2019 earnings at \$2.19 per share versus. \$3.25 a share in 2018. Third, the Company's inclusion of Evergy is inappropriate. This Company was formed by a recent merger of Great Plains Energy and Westar Energy. In early 2020, Elliot Management, an activist investor group, announced its purchase of a significant stake in Evergy. Elliot Management has been awarded two Board seats with these Board members representing 50% of a "Strategic Review & Operations Committee". The recent merger and the anticipation of further merger activity make this company unsuited to be included in a peer group used to determine the cost of capital for a more stable utility, such as Consumers Energy.

I find the other nine companies in Mr. Wehner's peer group suitable. However, the inclusion of NiSource, Evergy and Dominion make the Company's peer group unreliable.

Discounted Cash Flow (DCF) Cost of Equity Method

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

A. The DCF approach is based on the proposition that the price of any security reflects the present value of all future cash flows (dividend flows) from the security discounted at a single discount rate which, in the case of common stocks, is the required return 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

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-1.46. The stock price information in column (c) of this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from April 9, 2020 to May 21, 2020. The annual dividend in column (d) is the projected average dividend level for 2020 and 2021 as projected by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on (1) the estimate of earnings growth for years (2019 to 2024) per Value Line; and (2) the earnings growth estimate by stock analysts over the next five years which is available from Yahoo.com.

The resulting calculation of the DCF Method is an average return on common equity for the proxy group of 9.03%.

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 dividend and earnings growth prospects of security analysts which may or may not be consistent with the beliefs of investors. I place a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other methods in determining the cost of common equity.

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

A. The 9.03% rate I calculated is somewhat lower than the Company's "analyst-based" DCF calculation of 9.35% which is shown on page 5 of Exhibit A-14. The Company's exhibit also shows a range of results of 7.15% to 11.84% for this method. As explained earlier, I find Dominion Energy and Evergy to be unsuitable for inclusion in the peer group. If the results for these two companies are excluded, Mr. Wehner's cost of capital under the DCF is 9.02%, which is basically equal to my estimate.

<u>Capital Asset Pricing Model</u>

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

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

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

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

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

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

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

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

A. This measure of risk reflects the extent to which the price of a particular security varies in relationship to the movement of the overall market. Securities that vary over time more than the overall market will have a Beta that is greater than 1.00. Some securities vary less in price over time than the overall market. In these cases, the Beta will be less than 1.00. Utility stocks tend to move less than the overall market. Reflective of this outcome, the average Beta of the Peer Group is 0.66.

Q. PLEASE EXPLAIN EXHIBIT AG-1.47 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-1.47 shows the results of the CAPM method based upon (1) a 2.92% risk-free rate; (2) the Betas of the companies in the Peer Group taken from Value Line; and (3) the 6.91% historical Market Risk Premium (R_p) return from the years 1926 to 2018 developed by Company witness Wehner in Exhibit A-14 (TAW-1), Schedule D-5, page 8, line 51.

Regarding the use of a risk-free rate for CAPM purposes, I typically use the projected 30-Year U.S. Treasury Bond rate. However, currently the actual 30-Year Treasury rate has been around 1.5% and recent projections do not show any meaningful increase in the rate during the projected test year for this rate case. As shown on page 2 of Exhibit A-14

(TAW-1) Schedule D-5, the Company used a projected 30-Year U.S. Treasury rate of 2.92%. The Company's case was prepared before the COVID-19 pandemic and the economic contraction we are now experiencing. As such, the projected average 30 Year U. S. Treasury rates of 2.92% is a more reasonable choice for a CAPM analysis under relatively normal conditions.

Therefore, I decided to use the Company's forecasted risk-free rate of 2.92% in my analysis. The result of my CAPM method is a cost of equity capital of 7.04% after applying the 4.12% Beta-adjusted market risk premium to the risk-free rate of 2.92%.

Q. PLEASE ASSESS THE CAPM APPROACH.

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

Utility Risk Premium Approach

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

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

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-1.48 shows the two components required to estimate the cost of common equity under this approach and the resulting cost of equity rate of 8.67%. This exhibit shows the development of the ROE rate based on credit spread of utility bonds rated in the "BBB" category by S&P.

On line 3 of Exhibit AG-1.48, I start with the 4.3% forecasted BBB rate for the projected test year obtained from the Company through discovery.[27] Line 4 shows the historical spread of 4.37% for electrical utility common stock returns from 1931 to 2018 compared to utility bonds for the same timeframe. This rate is based on Mr. Wehner's Exhibit A-14 (TAW-1), Schedule D-5, page 9, line 89.

The sum of the two components is the cost of equity of 8.67%, as shown on line 5 of Exhibit AG-1.48.

[27] CECo response to discovery request AG-CE-588.

Q. HOW DO YOUR CAPM AND UTILITY RISK PREMIUM ROE RESULTS COMPARE TO THE RESULTS PRESENTED BY COMPANY WITNESS WEHNER?

A. Mr. Wehner shows the results of his Projected CAPM, Projected ECAPM and Projected Risk Premium methods in Exhibit A-14, pages 2, 3 and 4. In the table below, I show Mr. Wehner's ROE results compared to mine.

	ROE Recommendations		
	CAPM	ECAPM	Risk Premium
Company Estimates	14.30%	9.38%	15.67%
Attorney General Estimates	7.04%	N/A	8.67%

Q. WITNESS WEHNER PRESENTS TWO CAPM ESTIMATES IN THIS CASE. ONE IS SHOWN ON PAGE 3 OF EXHIBIT A-14 AND THE OTHER ON PAGE 1 OF EXHIBIT A-132. PLEASE COMMENT ON THESE TWO CAPM ESTIMATES.

A. On page 1 of Exhibit A-132 (TAW-20), Mr. Wehner calculates a CAPM cost of equity of 8.72% using the conventional model, albeit with an inflated short-term 10.33% risk premium rate of 10.33%. This risk premium rate is 3.42% above the historical 1926 to 2018 long-term risk premium of 6.91%. Not satisfied with the result of the conventional CAPM model, Mr. Wehner developed his own model, which he also calls a CAPM model.

Apparently, the conventional CAPM result of 8.72% did not support the Company's desired ROE request of 10.5%. In his own words, Mr. Wehner stated on page 46 of his direct testimony that because "…the CAPM methodology understates the required rate of return for utilities, it was not relied upon in forming the recommended ROE range in this case." Mr. Wehner also states on page 47 of his testimony that "In order to adjust for the shortcomings of the CAPM model, the Company performed an ECAPM analysis as well as a CAPM analysis using total beta." These are not conventional models used by most cost of equity experts, but simply fabricated calculations to achieve a desired result and should not be confused with and even called CAPM or ECAPM.

On page 3 of Exhibit A-14, Mr. Wehner calculates a ROE of 14.3% using his alternative approach. This approach uses a beta of 1.1 that he calculated on his own and the short-term inflated risk premium of 10.3% discussed earlier.

Q. PLEASE EXPLAIN THE DIFFERENCES BETWEEN YOUR ROE RESULTS AND THE RESULTS CALCULATED BY MR. WEHNER?

A. It is difficult to reconcile the differences between the methodology I used and Mr. Wehner's calculations, given the unconventional approach taken by Mr. Wehner. The best solution is for the Commission to totally dismiss Mr. Wehner's calculations as meaningless. However, to assist the Commission in assessing the shortcomings of the alternative approach taken by Mr. Wehner, I will attempt to explain his approach in more detail and identify the key differences to the generally accepted conventional CAPM methodology I used.

Mr. Wehner calculated a 14.3% ROE under his alternative CAPM approach by using a 1.1 beta factor. He calculated this beta on his own using a five-year standard deviation of stock returns of utilities in the peer group versus the overall stock market. In contrast, Value Line reported betas for the peer group that on average are 0.56, or approximately half the factor calculated by Mr. Wehner. Value Line has a very thorough and sophisticated approach to calculating beta factors that span long-term periods and are generally accepted by financial analysts. Mr. Wehner's calculations do not even remotely approach the accuracy and validity of the Value Line betas. For Mr. Wehner to suggest that utility stocks are riskier than the overall market is an unreasonable claim.

Mr. Wehner attempts to rationalize his calculations by raising two arguments on page 57 of his direct testimony. First, he argues that Consumers Energy is not a publicly traded company, and second that the Company is a Michigan-based utility and it can't diversify away from Michigan. Witness Wehner's arguments are specious at best. With regard to his first argument, Consumers Energy's management chose to form a holding company through CMS Energy so that Consumers Energy would no longer be a publicly traded company. This has become a common practice among utilities in the U.S. The peer group of publicly traded companies used to establish the cost of common equity mimics the cost of equity of a captive utility subsidiary as if it were a publicly traded company. This is a widely accepted approach by state regulatory commissions around the country when calculating the cost equity of privately-held and publicly traded utilities. Furthermore, Consumers Energy represents approximately 95% of the business of CMS Energy. Therefore, trying to impute some premium on the cost of equity because Consumers Energy's stock is not publicly traded as a subsidiary of CMS Energy is a poor argument.

Second, it is irrelevant that Consumers Energy cannot "diversify away from Michigan". The key factor to consider is that investors can "diversify away from Michigan" by adopting a portfolio approach to investments. Accordingly, Mr. Wehner's arguments have no merit and the Commission should disregard his testimony and his CAPM revisionist approach.

Regarding the risk premium issue, my calculations use the long-term historical risk premiums for both the CAPM analysis (6.91%) and the Utility Risk Premium analysis (4.37%). Each of these risk premiums have been calculated based on the relationship of the underlying stock and debt securities over multiple decades, and avoid the pitfalls of using volatile short-term calculations. For his alternative Projected ECAPM and Projected CAPM, Mr. Wehner utilizes a risk premium that is based upon projected returns in the stock market over the next five years based on data compiled by Bloomberg in December 2019. Page 10 of Exhibit A-14 shows the calculations used to develop the alternative projected risk premium of 10.30% for Mr. Wehner's version of the CAPM and ECAPM. The projected risk premium is approximately 3.5 percentage points higher than the historical average risk premium for the years 1926 to 2018 typically used.

For his alternative Projected Risk Premium approach, he uses a risk premium of 11.37% calculated by taking the difference of utility stock returns from utility bond returns from two short-term periods in 1942 to 1951 and the period 2011 to 2018. Using the term "Projected" to label his calculation is a misnomer since it involves select historical information which fits the Company's objective but is not logical or generally accepted. Page 9 of Exhibit A-14 shows the calculations used to arrive at this alternative risk premium. The result is a risk premium that is approximately seven percentage points higher than the long-term historical average of utility stocks to bonds over 88 years as shown in the same exhibit.

Q. WHAT SHORTCOMINGS DO YOU SEE WITH THE RISK PREMIUMS DEVELOPED BY MR. WEHNER?

A. In the case of his alternative Projected Risk Premium, Mr. Wehner is using two extremely short historical periods to measure results and determine his risk premium. The first of these is 1942 to 1951 which represents the World War II economic boom and the six years thereafter. While it is true that interest rates were controlled and suppressed during this time period, an examination of the basic data shows that it is the significant equity returns generated by the war that drove the excess returns and not interest rate levels. Also, the Commission should recognize that the second period Mr. Wehner selected, which is the 2011 to 2018 timeframe, is less than one full economic cycle and reflects a period of economic expansion and significant stock market appreciation. Selecting only these two periods, as witness Wehner has done, produces an upwardly biased risk premium which is not reflective of long-term reality.

The use of Bloomberg data to project a risk premium as of December 2019 reflects the optimism among investors at that point in time about the projected short-term period of five years. Given the short-term nature of the projected data and the state of the economy at that point in time, the Company's calculations rely upon forecasted market risk premiums that reflect short-term continued expansion. The forecasted market data used by witness Wehner do not include a complete cycle of economic expansion and contraction, which is what occurs over the long-term. For the Commission to adopt this approach, it would be akin to only selecting the positive return years over the historical 92-year period commonly used and not the losses in the downturn years. Expectedly and incorrectly, we would derive a far higher overall return for the market and a far higher market risk premium, similar to what witness Wehner has done.

For all of the above reasons, Mr. Wehner's development of risk premiums for his alternative Projected CAPM, Projected ECAPM and Projected Risk Premium methods is seriously flawed.

Q. WHY IS THE USE OF A SHORT PERIOD INAPPROPRIATE IN CALCULATING THE RISK PREMIUM FACTOR?

A. The use of a short time period to calculate the market risk premium does not take into consideration the stock market returns during both expansion and contractions in the economy. To determine an appropriate expected market return and risk premium, multiple economic cycles over a long timeframe must be taken into account. Otherwise, the calculations of market risk premiums would result in very high ROEs during periods of economic expansion, as Mr. Wehner has calculated under his unconventional approach. Similarly, during periods of economic contraction and losses in the stock market, we would see very low and possibly negative risk premiums. Using such short-term data results in illogical outcomes when calculating expected long-term investor returns for purposes of establishing a reasonable ROE.

These concerns are also echoed by Dr. Roger Morin who favors the use of the longest possible period for calculating a market risk premium. On page 114 of his book "New Regulatory Finance" Dr. Morin states the following:

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

Clearly, Mr. Wehner's approach to calculating projected market risk premiums is not academically or practically sound. As such, I view his alternative cost of equity calculations as unreliable and merely an attempt to produce a result that is more favorable to the Company. The Commission should give those ROE calculations no weight.

Q PLEASE COMMENT ON MR. WEHNER'S USE OF THE ECAPM METHOD.

The basic premise for the use of the ECAPM method is that the Beta factors published by Value Line when used in CAPM analysis do not accurately predict stock performance. However, as explained below, this argument is flawed.

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

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

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

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

A. No. In response to a discovery request in Case No. U-18424, the Company stated that ECAPM "… is supported by orders from regulatory bodies in Maryland, Mississippi and Alberta…" As a result of this claim, the Company was asked to provide the specific rate orders from these regulatory commissions.[28] The information provided in response to this discovery request was less than convincing.

Regarding the purported acceptance of the ECAPM in the State of Mississippi, the filing requirements of the Mississippi Commission require ECAPM filings. However, the extent to which Mississippi relies upon these estimates is unknown.

Regarding the Maryland commission, Mr. Maddipati, the Company's cost of equity witness in Case No. U-18424, stated on page 58 of his direct testimony that the Maryland Commission found the DCF and ECAPM "helpful" in Case 9326. However, in a subsequent case involving PEPCO (case 9418) with an order issued on November 15, 2016, the result is different. As shown in the summary positions articulated in the order in this case, no party involved in the proceedings, other than the company, put forth an ECAPM ROE estimate. In this case, the Maryland commission basically adopted the Staff's position with no ECAPM estimate and rounded down the Staff's recommended ROE of 9.57% to 9.55%. In this regard, the Commission stated on page 100 of the order the following. *"Our Decision today most closely aligns with Staff's recommendation of 9.57% although we do not expressly reach the same conclusion as Staff. We find that a*

[28] CECo responses to U-18424 AG-CE-206 and AG-CE-386.

slightly lower ROE of 9.55% is both adequate and appropriate for Pepco…" Furthermore, in its decision in this case, the Maryland commission expressed no position on ECAPM.

The Alberta Utilities Commission decision provided by the Company (Decision 20622-D01-2016) is dated October 7, 2016. This decision results from a generic proceeding regarding cost of capital for a number of utilities. The Alberta commission noted on page 45, paragraph 199 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, the commission noted the high degree of judgment required by the ECAPM methodology and stated: *"Consequently, the Commission will not rely heavily on the ECAPM results in this proceeding…"*

On pages 53 to 55 of his testimony in this rate case, Mr. Wehner also points to a case in Alaska decided in 2002 where the Alaska Commission gave formal recognition to an adjustment for ECAPM, but he presents no more recent information on the Alaska Commission's views on this methodology. He also claims that the New York State Public Service Commission uses a so-called "zero beta" CAPM model that supposedly is similar to the ECAPM. However, his claim is unsubstantiated. The fact that other cost of capital practitioners representing utility companies have used the ECAPM model in other cases to boost the proposed ROE rate does not mean that the methodology has been endorsed by the regulatory commissions adjudicating those rate cases.

In summary, the use of ECAPM is controversial and not widely accepted by state regulatory commission regulating gas and electric utilities. The Commission should disregard the Company's ECAPM cost of equity estimate.

Q. PLEASE COMMENT ON MR. WEHNER'S COMPARABLE EARNINGS ANALYSIS.

A. As shown on page 6 of Exhibit A-14 (SM-1), Schedule D-5, Mr. Wehner derives a 10.36% projected average ROE rate based on the forecasted earnings divided by the book value of common equity for his peer group. His overall recommended ROE of 10.50% relies on this estimated return on equity rate.

Unfortunately, this is not an academically sound approach to determine the cost of common equity for any company. What Mr. Wehner is doing is simply dividing (1) the projected earnings per share ("EPS") approximately four years from now for each peer group company (as estimated by Value Line) by (2) the projected Book Value for each such peer group company. This exercise perhaps has some use in evaluating how well each peer group company employs capital over longer periods of time but is useless as a tool to set the authorized ROE of a utility company. This method does not take into account investors' expectations or stock market parameters.

The Commission should also recognize the inherent circularity in relying upon this method advocated by the Company. If utility commissions were to rely upon this methodology, utilities in effect would indirectly be setting their own allowed ROE or highly influencing those ROEs by estimating ever increasing EPS.

In summary, this approach appears to be another attempt to find a cost of capital calculation method to fit a desired level of return on equity. My recommendation is that the Commission should give no weight or reliance to this alternative method.

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE GRANTED IN 2018 AND 2019.

A. Since 1990, the return on equity rates approved by regulatory commissions in gas cases has been on a steady decline from over 12.7% in 1990 to approximately 9.6% in 2018 and 2019. This decline has generally followed the significant decline in interest rates and the rate of inflation.

Exhibit AG-1.50 shows the ROEs granted by state regulatory commissions for U.S. electric utilities in 2018 and 2019. The majority of the 38 ROE decisions in 2018 and 33 decisions in 2019 are at rates well below 10%. As noted on page three of this exhibit, only 4 decisions in 2018 and 9 decisions in 2019 are at rates of 10% or greater. These higher rates (summarized on page 3 of my exhibit) are primarily from regulatory commissions in Michigan and Wisconsin which represent outliers among other regulatory commissions around the country. ROEs in California have been over 10% reflecting the unique challenges of that state (wildfires and earthquakes). Another high ROE case indicated on page 3 of my exhibit is for Georgia Power at 10.50%. I will point out that this company is facing difficulties in the construction of two nuclear power plants. Unfortunately, the original contractor went into bankruptcy and the project has faced significant delays with the Company writing off approximately $1.1 billion of cost over-runs. While the Georgia Commission has been very supportive during this troubling time in Georgia Power's history, it did recently reduce the ROE by 50 basis points.

For most of the other electric utilities that have business and financial risks comparable to Consumers Energy's electric operations, the ROE rates have averaged around 9.5% in the past two years. This evidence supports my proposed ROE rate of 9.50% and makes the Company's current ROE rate of 10.00% excessive. The Company's proposed ROE rate of 10.50% is even further removed from reality and clearly unsupportable.

Q. PLEASE COMMENT ON WITNESS WEHNER'S CHART ON PAGE 35 OF HIS TESTIMONY WHERE HE POINTS TO SIX EXAMPLES OF COMPANIES WITH ROE'S OF 9.9% TO 11.0%?

A. This information is incorrect in many instances and misleading in other respects and he does not provide any proper context for the metrics he notes in this chart.

First, with regard to Florida Power & Light, I will point out that the 10.55% ROE was established by the Florida Commission in 2016 as part of a multi-year agreement covering the years 2017 to 2020. As such, this ROE rate is stale, and we should see a new agreement soon covering 2021 and beyond with a lower ROE given industry trends. In addition, this

Company's service territory is buffeted by hurricanes each year which can disrupt electric service for prolonged periods and potentially impact its profits.[29]

Second, witness Wehner indicates that Alabama Power has a 55% common equity ratio and a 10.9% ROE. This is misleading at best. At a 55% common equity level, no increase in rates would be permitted unless the ROE was below 10.5%. While 10.5% is a higher level ROE, it is important to keep in mind that these numbers reflect a long-term formulistic rate setting arrangement which forces this company to contain costs. In general, Alabama Power can increase it rates each year but on a rolling two-year basis, the rate increases are limited to no more than 8% (4% on average annually). The rate increase is authorized under the company's Rate RSE (established several years ago) which is determined by considering the level of earned returns on equity and the percentage of equity in the capital structure.

In 2018, the Alabama Commission and the company agreed that a higher common equity ratio of 55% is desirable by 2025 and that the company would gradually move toward this higher level versus 47% at December 31, 2018. This change to Rate RSE for Alabama Power was approved in May 2018 with no compensating rate increases and the company at that time consented to a nominal reduction in the weighted cost of capital and no annual Rate RSE increases in 2019 and 2020. As such, what is happening in this situation is that the company is increasing the common equity ratio gradually with no compensating

[29] Based on page 9 of NextEra's 2016 Form 10-K which summarizes the 2017 to 2020 agreement.

increases in the weighted cost of capital. The practical effect of these rate actions is to reflect recognition of a lower cost of common equity. I will add that the last time that Alabama Power increased its Rate RSE revenues was on January 1, 2017. Since then, the company has established significant Rate RSE refund liabilities related to 2018 and 2019. The portrayal of Alabama Power as top tier ROE utility in Mr. Wehner's chart on page 35 of his testimony is very misleading.[30]

Witness Wehner also shows that Georgia Power has a 55% Common Equity level and an 11% authorized ROE. According to Regulatory Research Associates, the ROE was reset by the Georgia Commission at 10.5% in December 2019. Also, this company is in a special situation involving significant expenditures for two nuclear power plants where the original contractor declared bankruptcy and the Company has been forced to write-off approximately $1.1 billion of cost overruns.[31] While the Georgia Commission has been very supportive of this company through this troubled time in its history, it recently reduce the authorized ROE by 50 basis points.

Additionally. Mr. Wehner shows WEC, which operates in Wisconsin and in other jurisdictions, as having an average 10.6% ROE. I will point out that according Regulatory Research Associates all recent decisions from the Wisconsin Commission in general rate cases have contained a ROE of 10% or lower. Mr. Wehner may have boosted up the ROE

[30] Based on Southern Company 2019 Form 10-K, pages II-196 and 197.
[31] See Southern Company 2019 Form 10-K page II-145 showing the write-off of such cost overruns, and also pages II-206 and 207 for further discussion of the power plant construction issues.

level in his chart by including Limited Issue Rider cases. WEC also is a holding company and as such it does not have an allowed ROE, its subsidiaries do.

Another Company that Mr. Wehner points to is Virginia Electric Power (or VEPCO) and he claims that the ROE for this company is 10.0%. During 2019, Regulatory Research Associates reports that rate orders in 2019 for this company consisted of only ten Limited Issue Rider cases. Six of the orders were at a 9.2% ROE and four of the orders were at 10.2%. This reflects an average ROE of approximately 9.5% which is in line with my recommendation.

Finally, witness Wehner points to UGI and its electric operations in Pennsylvania and indicates that this UGI unit has an authorized ROE of 9.9% and a 54% common equity ratio. All of this is true, but what Mr. Wehner does not mention is that this small operation serves only 66,000 customers in two Pennsylvania counties.[32] These return metrics may very well be justified based on this company's size. However, this situation is hardly comparable to Consumers Energy.

This in-depth analysis of the unusually high ROE rates presented by Mr. Wehner shows that the information is either stale, unique to special situations or misleading, and should not be relied on by the Commission to reach a conclusion on the proper ROE rate to be granted to Consumers Energy in this rate case.

[32] See page 19 of the UGI 2018 Form 10-K.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE OF 9.50% IN THIS CASE WILL LEAD TO IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?

A. No. In recent general rate case proceedings, 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. Exhibit AG-1.50 shows several electric 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-1.49 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 approximately 2.0 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 Consumers

Energy. Other electric 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. ON PAGE 52 OF ITS SEPTEMBER 13, 2018 ORDER IN CASE NO. U-18999 AND RECENTLY IN DTE ELECTRIC RATE CASE U-20561, THE COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO AUTHORIZE THE ROE RATE. SHOULD STOCK MARKET VOLATILITY OR THE VIX INDEX BE A CONCERN IN ESTABLISHING A FAIR ROE RATE FOR THE COMPANY?

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

As a second point, in Exhibit AG-1.54, I have included a Value Line Funds article written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not risk. He also points out that volatility in 2017 was low by historical standards and it was near normal levels in 2018. Mr. Appel goes on to say later in this article that “…volatility is only risk if you act during down times, that is, only if you sell a stock.”

Additionally, I will submit that those who invest money in equity portfolios over longer periods of time and particularly in utility stocks have an aversion to market volatility and the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market. This is reflected in the average Beta value of 0.60 of the utility peer group used in the CAPM discussed earlier, in contrast with the general stock market value of 1. Therefore, the Commission should not give any weight to arguments that the Company's ROE should reflect investors' concerns with stock market volatility.

Q. HAS THE MARKET FOR NEW LONG-TERM DEBT BEEN RECEPTIVE TO UTILITY ISSUING DEBT DURING THIS PERIOD OF ECONOMIC TURMOIL CAUSED BY THE COVID-19 PANDEMIC?

A. Yes. As noted on Exhibit AG-1.50, many of the companies issuing debt recently did so in March, April, May and June of 2020. Spreads over comparable treasury bonds have widened but this is because U.S. Treasury rates have fallen to historic lows as the Federal Reserve Bank has moved to reduce interest rates due to the COVID-19 pandemic and the related economic turmoil.

Consumers Energy issued $575 million of new 31-year long-term debt in March 2020 at 3.5%, making it one of its lowest cost long-term debt issues in recent years. Accordingly, the debt markets have receptive to electric utility companies issuing debt capital at very attractive interest rates.

Similarly, the common equity markets have recovered after the significant decline in March 2020 to levels comparable to the beginning of 2020.

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

A. In Exhibit AG-1.45, I have summarized the cost of equity rates from the three methods I discussed above. The range of returns for the industry peer group is from 7.02% at the low end, using the CAPM approach and 9.03% at the high end using the DCF approach.

As explained earlier in my testimony, I give 50% weight to the DCF method as a more reliable approach to estimating the cost of equity, which from my analysis is a rate of 9.03%. In this regard, on line 4 of Exhibit AG-1.45, 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 average cost of common equity of 8.44%. To this base cost of equity capital, I have added an additional premium adjustment of 106 basis points to arrive at a recommended ROE rate of 9.50% for Consumers Energy's electric business for the reasons explained below.

First, the current state of the economy and financial markets has increased business and financial risk to some degree. The 106 basis points I have added to the calculated cost of equity provide a cushion to absorb the impact of these higher risks.

Second, I understand that the Commission would be reluctant to grant a ROE at the 8.44% as the true cost of capital at this time, preferring instead a more gradual reduction. The 9.50% ROE rate I have proposed is a reasonable reduction from the last granted ROE of 10.0% granted to the Company's electric business approximately 18 months ago.

Third, the 9.5% proposed ROE is in line with the average ROE granted to other electric utilities by state regulatory commissions around the country during 2019.

Q. IF THE COMMISSION APPROVES A 10.00% COST OF COMMON EQUITY IN THIS CASE, WHAT IS THE COST TO CUSTOMERS COMPARED TO AN ROE OF 9.50%.

A. If the Commission were to grant a 10.00% ROE in this case versus a 9.50% ROE, the additional cost to customers is approximately $34.2 million annually. There is absolutely no need to burden customers with this additional cost, when historically the Company has been earning well above its true cost of common equity.

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 9.50%.

Q. IF THE COMMISSION LOWERED THE AUTHORIZED ROE FROM 10.00% TO THE TRUE COST OF COMMON EQUITY OF 8.44% IN THIS CASE, WHAT WOULD BE THE REDUCTION IN THE REVENUE REQUIREMENT?

A. If the Commission were to grant an 8.44% ROE in this case versus a 10.00% ROE, the reduction in the revenue requirement would be approximately $103 million annually.

VI. Operations and Maintenance Expenses

Q. WHAT ARE YOUR FINDINGS IN ANALYZING THE COMPANY'S LEVEL OF O&M EXPENSES INCLUDED IN THIS RATE CASE?

A. My review of Exhibit A-13 (HJM-53), Schedule C-5, shows that O&M expenses are projected by the Company to be approximately $684.7 million for the future test year, an increase of $110.7 million, or 19% from 2018.

Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE OTHER O&M COSTS SHOULD BE REDUCED?

A. Yes. I have analyzed O&M costs by major department or area, and I have identified more appropriate and reasonable expense levels that the Commission should consider. Based on my analysis of various areas of expense, I recommend that forecasted O&M expenses should be reduced by $99.0 million to a level of $585.7 million. Exhibit AG-1.55 shows a summary of my proposed O&M expense adjustments.

A. Electric Distribution

Q. WHAT ADJUSTMENTS DID THE COMPANY MAKE TO ITS ELECTRIC DISTRIBUTION EXPENSES?

A. As indicated on Company Exhibit A-36 (RTB-9), the Company's expense in this area was $140.6 million in 2018 and the Company has forecasted an expense of $170.7 million for the 2021 test year. This is a 21% increase over a three-year period.

The following table summarizes the major changes.

	$ Millions		
	2018	Increase	2021
Service Restoration	$ 53.9	$11.2	$ 65.1
All Other	86.7	18.9	105.6
Total	$140.6	$30.1	$170.7

In Exhibit AG-1.56, I show the trend in these costs, and some of the components, from 2014 to 2019. For example, the exhibit shows that Service Restoration expenses have fluctuated from $35.5 million in 2016 to a high of $92.1 million in 2019. The unpredictable nature of these costs reflects changes in weather (wind and ice) from year to year and the impact of these factors on the Company's costs. The other components of O&M expense for Electric Distribution have been more stable ranging from $77.7 million in 2017 to a high of $91.5 million in 2014.

To establish a reasonable level of Service Restoration costs for the projected test year, I used a five-year average of actual expenses from 2015 to 2019. The resulting amount is $54.0 million. Given the variability of restoration costs, the use of a five-year average is a reasonable approach. In its recent rate case No. U-20561, DTE Electric proposed a five-year of actual costs from 2014 to 2018 and the Commission accepted that approach with no party to the case objecting to the approach.

The Company has proposed an expense level of $65 million based on a three-year average of actual costs from 2017 to 2019. The Company's premise is that there has been a significant increase in storm activity in recent years and a shorter average period is warranted. The information shown in Ms. Brenda Houtz's direct testimony is for a short time period and distorts the reality about the frequency and severity of storms over the past decade. For example, in Figure 11 on page 16 of her direct testimony, she shows the number of wind-caused incidents from 2015 to 2019 and concludes that there is an increasing trend of incidents in recent years. Similarly, on page 18 of her testimony, she shows the number of Major Event Days (MEDs) on a rising slope from 2015 to 2019.

However, in discovery, the Company was asked to provide a longer-term record of weather incidents and the number of customers impacted. In response to several discovery requests, which are included in Exhibit AG-1.62, the Company provided information that shows that the number of severe storms between 2010 and 2013 were higher than in the most recent five years, and more customers were impacted by weather events during that time period. Therefore, the Company's justification to use a three-year average to forecast restoration costs for the projected test year is faulty and should not be accepted by the Commission.

The Company has also proposed a mechanism to defer restoration costs over a certain threshold and to recover those costs in future years. I will address that proposal later in my testimony as a separate item.

Q. IN HER TESTIMONY, MS. HOUTZ ALSO CLAIMS THAT RESTORATION COSTS ARE NOW HIGHER THAN IN PRIOR YEARS DUE TO THE NEWLY EXPANDED INCIDENT COMMAND SYSTEM (ICS) AND HIGHER MUTUAL ASSISTANCE COSTS INCURRED IN 20219. HOW DO YOU RESPOND?

A. The Company has certainly expanded the ICS and added hundreds of people to manage the ICS both on an on-going basis and during significant weather emergencies. The number of people involved in the ICS skyrocketed in 2019 from 600 to 900 people with the Company assigning fewer tasks to more individuals and supervisory groups. Ms. Houtz claims that the expanded ICS has already proven successful in 2019. Based on the information provided in discovery and included in Exhibit AG-1.62, which shows the number of days to recover from a large storm since 2010, the jury is still out. The Company was able to manage the restoration of more customers during larger storms 10 years ago in an equivalent amount of time.

In increasing the number of employees assigned to the ICS and subdividing work to smaller units with more supervision, the Company may have unreasonably increased the cost of managing the ICS. Adding more people to the ICS team and subdividing work into smaller units is not always the most effective solution. The Company will need to monitor this change in coming months to determine if the added cost is justified by a significant reduction in restoration time from major outages.

With regard to MA costs, given the number of storm incidents, not only in Michigan but in other parts of the country, the costs to obtain assistance from other utilities and contractors increased significantly in 2019. However, even the Company concedes that the cost escalation in 2019 was unusual and is not expected to continue.[33]

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO DISTRIBUTION EXPENSES?

A. Yes. In Exhibit AG-1.56, I have taken the base O&M expense of $81.2 million for the most recent actual period of 2019 and have added the $54 million of service restoration costs to arrive at total expense amount of $135.2 million. I have increased this amount for the forecasted annual CPI rate of 0.5% for 2020 and 2.3% projected by IHS Markit[34] as of April 2020 to arrive at a forecasted expense for the projected test year of $139.0 million.

The Company forecasted Distribution O&M expense of $170.7 million. My forecast of $139.0 million reduces the projected test year expense by $31.7 million.

Q. WHY ARE THE COMPANY'S EXPENSES IN THIS AREA FAR HIGHER THAN YOUR FORECAST?

A. First, the Company's Storm Restoration costs are higher than my five-year average by $11.1 million. Second, the Company is projecting far higher costs in many other categories with insufficient justification being provided. For example, the Company wants to spend

[33] CECo response to AG-CE-1166b.
[34] Exhibit AG-1.66 includes CECo response to AG-CE-602.

significantly higher dollars for training for new hires to replace retiring employees and expanded workload.

However, in response to discovery, the Company provided information that shows the number of forecasted retirements over the next three years are in line with historical numbers in the past five years. Similarly, the number of new hires for field employee positions for the next two years is within the historical range of 22 to 78 hires. Exhibit AG-1.63 includes the discovery response.

The Company has also forecasted O&M expense increases in other areas, such as LVD Device Management of $1.2 million, Grid Management, and also supervisory and administrative staff without providing sufficient support to justify the increase.

In conclusion, the Company's forecasted expense level for Electric Distribution for the projected test year is unreasonably high at $170.7 million. My estimate of $139.0 million reflects a more reasonable expense level reflective recent experience. The Commission should reduce the level of expense in this area by $31.7 million.

B. Vegetation Management

Q. WHAT LEVEL OF EXPENSE FOR LINE CLEARING OR VEGETATION MANAGEMENT DID THE COMPANY PROPOSE AND HOW DOES IT COMPARE TO THE HISTORICAL TEST YEAR?

A. As shown in Exhibit A-98 (CAS-1), the Company proposed to increase the expense for vegetation management to $84.0 million for the projected test year from the $51.9 million spent in 2018. This new level is an increase of 62%. According to the exhibit and the direct testimony of Chris Shellberg, the majority of the increase is for clearing the Company's Low Voltage Distribution lines. Vegetation expenses for LVD lines are projected to increase from $39.9 million in 2018 to $71.4 million, or a 79% increase. In direct testimony, witness Shellberg states that by moving to this higher expense level, the Company can achieve a 10-year cycle in line clearing versus the current 14-year cycle.[35] The Company's objective is to achieve a 7-year cycle by 2025.

Q. WHAT CONCERNS DO YOU HAVE WITH THE COMPANY'S VEGETATION MANAGEMENT PROPOSAL?

A. I have two major concerns. First, on page 17 of the direct testimony, witness Shellberg shows that the cost for clearing lines per mile has increased from approximately $6,000 per mile in 2004 to approximately $12,000 per mile in 2018. The higher amount in 2018 reflects an average rate of increase of approximately 5% per year in comparison to the annual rate of increase in the CPI of 2.1% over the same timeframe. The extent to which the higher cost per mile in recent years is affected by changes in tree density is uncertain. However, the Company needs to be very attentive to the issue of escalating costs and needs to put controls in place to ensure that any increase in spending granted by the Commission

[35] See Figure 8 on page 18 of Chris Shellberg's direct testimony.

does not go toward paying higher contractor rates, but instead toward clearing threes from around power lines.

Second, I question the Company's ability to quickly scale tree clearing operations in 2021 to the proposed $84.0 million in a short time period after receiving an order in this case sometime in December 2020. In discovery, the Company was asked this question. In its response, which is included in Exhibit AG-1.64, the Company dismissed the issue by stating that it would offset the delayed escalation of crews by working overtime. This is not an effective means to clear more trees given the premium rate to be paid for overtime work. A more effective approach would be to gradually scale up with the required crews and equipment and increase tree-trimming activity.

Q. HOW DO YOU PROPOSE TO ADDRESS THESE CONCERNS WHILE PERMITTING THE COMPANY TO RAMP-UP ITS LINE CLEARING EFFORTS?

A. The Company's proposal is for the Commission to approve a $31 million increase in Line Clearing expense from approximately $53 million in 2019 and 2020 to $84 million in 2021. This is a large increase in spending to be accomplished in a year. It is likely that the Company would receive the higher amount in rates and not be able to spend it or as stated earlier undertake inefficient steps to spend the money by paying overtime rates for part of the year.

My recommendation is that the Commission include only an additional expense amount of $15 million for Line Clearing expense in this rate case for a total amount of $68 million for the projected test year. In addition, the Commission would authorize the Company to spend up to an additional $16 million above the amount in rates to a maximum amount of $84 million and defer any amounts spent annually between $68 million and $84 million for future recovery in its next rate case. The deferred balance would be amortized over a five-year period.

To promote accountability for results, the full recovery of the deferred annual amount would dependent upon the Company achieving at least the projected annual miles of tree clearing for 2021 shown in Exhibit A-98 (CAS-1) for HVD and LVD lines, and also achieving the cost per mile for 2021 of $11,173 for HVD and $13,676 for LVD lines. For the first year of the expanded program in 2021, the Company would only recover an amount equal to the number of miles completed over the $68 million in rates at the rate per mile assumed for 2021 in Exhibit A-98 up to $84 million. For future years after 2021, the Commission could allow a 2% annual escalation to the cost per mile completed.

C. Power Generation

Q. THE COMPANY RECOMMENDED $166.8 MILLION OF O&M EXPENSE FOR ITS POWER GENERATION AREA. WHAT ADJUSTMENTS DO YOU RECOMMEND TO THIS FORECASTED EXPENSE AMOUNT?

A. Page 1 of Exhibit A-70 (SAH-5) shows O&M expense increases from $148.2 million in 2018 to $166.8 million for the projected 2021 test year.

As explained below, I recommend that O&M expense in this area be reduced by $6.4 million to $160.4 million. In Exhibit AG-1.57, I show the trend in expense from 2014 to 2019. The exhibit shows Major Maintenance expense and the 2019 expense related to the Karn Separation and Retention Payments separately from the other expenses. Other expenses on line 3 show a slight downward trend. These expenses were $142.2 million in 2014 and have declined to $113.9 million in 2017, $120.4 million in 2018 and $109.2 million in 2019.

To build his projected test year expense amount, Company witness Hugo started with the expense amount from the 2018 historical test year. Because of the lower cost levels in 2019 and 2017, I believe that the development of an average cost level for the three years 2017 to 2019 is an appropriate starting point. The average cost level for the three years is $114.5 million, as shown in column (h) of Exhibit AG-1.57. To this amount I added $3.2 million to reflect inflation and also the estimated costs for major maintenance, and the Karn Separation and Retention Payments. The result is a reasonable forecast of $160.4 million, as shown on line 10 of the exhibit.

The key difference between the Company's cost estimate and my cost estimate is the starting point for Other Expense. Witness Hugo uses the higher 2018 cost level of $120.4 million. In contrast, I used an average expense level from 2017 to 2018 which is $114.5

million. I believe my cost forecast of $160.4 million is more representative of future costs and a reasonable forecast of O&M expense for the projected test year.

I recommend that the Commission reduce the Generation O&M expense proposed by the Company in this rate case by $6.9 million.

D. Uncollectible Accounts Expense

Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO THE COMPANY'S FORECASTED UNCOLLECTIBLE ACCOUNTS EXPENSE.

A. In Exhibit A-64 (KMG-4), the Company proposed $18.1 million of uncollectible accounts expense for the projected test year based on a 3-year average of net charge-offs to revenue for the three years 2016 to 2018.

In discovery the Company was asked to provide updated information for the three-years 2017 to 2019. Based on the information provided in the response to discovery request AG-CE-655, which is included in Exhibit AG-1.64, I have recalculated the forecasted expense at $16.9 million for the projected test year. Exhibit AG-1.64 shows the calculation. The difference is $1.2 million from the Company's forecast.

The 2017 to 2019 information is more recent data and therefore is preferred over the information used by the Company. Therefore, I recommend that the Commission remove $1.2 million from the Company forecasted uncollectible accounts expense for the projected test year.

E. Injuries & Damages

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE COMPANY'S PROJECTED EXPENSES FOR INJURIES AND DAMAGES?

A. The Company proposed $4.5 million for Injuries and Damages expense for the projected test year, as shown on Exhibit A-65 (KMG-5). The expense is based on a five-year average of the actual expenses incurred for 2014 through 2018.

Based on 2019 information obtained from the Company through discovery, which I have included in Exhibit AG-1.65, I have recalculated a five-year average for the years 2015 to 2019. The more recent five-year average is $3.8 million, as calculated in Exhibit AG-1.59 which is lower than the Company's estimate by $0.7 million.

I recommend that the Commission reduce the Company's forecasted expense amount for this item for the projected test year by $0.7 million.

F. Corporate Expenses

Q. DO YOU PROPOSE ANY ADJUSTMENTS TO CORPORATE EXPENSE?

A. Yes. The Company forecasted that Corporate O&M expense will increase to $56.8 million in the projected test year. This is an increase of $11.3 million from the adjusted historical amount of $45.5 million in 2018. Exhibit A-62 (KMG-2) shows that the Company developed the projected test year forecast by escalating the 2018 labor costs by 3.2% annually and increasing the 2018 non-labor costs by rates of 1.5% to 2.3% annually from

2019 to 2021. The Company also made some normalizing adjustments to 2018 reported expense.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S CORPORATE O&M FORECAST?

A. The historical corporate expense in the most recent five years from 2015 to 2019 has ranged from $45.5 million to $56.9 million with the low end of this range occurring in 2018. The average expense over the three-year period has been $49.5 million which is slightly lower than 2019 actual costs. Exhibit AG-1.60 shows this information based on data received from the Company in response to discovery.

The first four lines of the exhibits show how the Company developed its projection of $56.8 million for the test year. The Company normalized the 2018 reported expense for a large insurance refund in 2018.

The Company has escalated Corporate expenses for labor at a 3.2% annually and non-labor costs at the CPI rate forecasted as of November 2019. The combination of these two cost escalation rates results in a blended inflation rate that is higher than the CPI rate. In prior rate cases, the Commission has rejected the use of blended inflation rates and has approved only the most recent CPI rate provided by Staff or the AG.[36]

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[36] MPSC Case No. U-20162 and U-20561.

The approach I have taken to forecast Corporate Expenses is to use a three-year average of the actual normalized expenses incurred from 2017 to 2019 and applied the most recent CPI rate for 2020 and 2021 provided by the Company in response to discovery. Exhibit AG-1.60 shows the calculations and result. Using this approach, I have calculated a test year projected expense of $50.9 million. This amount is $5.9 million lower than the Company's forecast.

I recommend that the Commission remove the $5.9 million from the Company forecasted O&M expense for the projected test year.

G. Active Health Care Expense

Q. PLEASE DISCUSS THE COMPANY'S PROJECTED EXPENSE FOR ACTIVE HEALTH CARE, LIFE INSURANCE AND LONG-TERM DISABILITY.

A. Line 4 of Exhibit A-51 (LBC-1) shows actual health care, life insurance and disability (Health Care & Other) costs of $24.2 million in 2018 and increasing to $27.5 million for the projected test year, which is a 14% increase in three years.

Beginning on page 16 of her direct testimony, Ms. Christopher discusses several factors for the increase in Health Care & Other costs. Ultimately, she chose annual rates of increase of 4%, 2.3% and 6% for 2019, 2020 and 2021, respectively, that she applied to the 2018 actual costs to arrive at the projected year expense of $27.5 million.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECASTED EXPENSE?

A. The forecasted rates of health care cost increases used by Ms. Christopher overstate the forecast expense for the projected test year and do not reflect the actual cost increases experienced by the Company in recent years. In Exhibit AG-1.61, I used the actual Health Care & Other costs from 2014 to 2019 provided by the Company to determine the actual trend in costs. Costs over this historical period show no increase. In fact, health care costs were $25.4 million in 2014 and are still $25.4 million in 2019 with lower amounts in the years in between. This information contradicts the inflation rates of up to 6% used by Ms. Christopher and sourced from various health care consultants. It is not clear how consultants have calculated these projections, but I have found from similar information provided by the Company in prior rate cases that the projections are consistently over inflated and unreliable, at least with regard to the actual cost increases experienced by the Company.

Although over the past five years health care costs have been flat, to give the Company the benefit of the doubt that it may experience some increases in costs, I have calculated a 2.5% rate of increase during the three-year period from 2017 to 2019. In Exhibit AG-1.61, I used this 2.5% average rate of increase to forecast Health Care & Other costs for the projected test year based on the actual costs of $25.4 million incurred in 2019. The result is a projected test year expense of $26.5 million. This expense amount is $1.0 million less than the Company's forecast of $27.5 million.

I recommend that the Commission remove the $1.0 million from the Company's projected test year expense.

H. Information Technology Investment– Expense

Q. WHAT LEVEL OF O&M EXPENSE IS THE COMPANY PROPOSING FOR INFORMATION TECHNOLOGY – INVESTMENTS?

A. In Exhibit A-132 (CJV-2), the Company shows $16.1 million of expense in 2018 with the expense level increasing to $21.9 million in the projected test year. The $5.8 million increase in expense represents a 36% increase over the 2018 cost level and seems excessive.

In response to discovery, the Company provided the O&M expense for the five years from 2015 to 2019. During this historical time period, O&M expense has ranged from a low of $9.0 million in 2016 to a high of $16.1 million in 2018, and has averaged $12.7 million annually.[37] For 2019, the Company incurred $10.9 million of actual expense which is in line with the average expense over the 5-year period. In fact, the Company had forecasted $13.9 million in expense for the year 2019 and actual expense was approximately $3.0 million less.

Q. PLEASE EXPLAIN WHAT TYPES OF COSTS ARE CHARGED TO INFORMATION TECHNOLOGY – INVESTMENT EXPENSE.

[37] Exhibit AG-1.67 includes CECo response to DR AG-CE-672 Attachment.

A. According to Company witness Christopher Varvatos in Case U-20650, project upgrades and technology investments for new IT capabilities have a Preliminary Project Stage and a Developmental Stage recognized under FASB accounting rules. Costs incurred during these stages are required to be expensed even though other related costs must be capitalized.[38] As such, it is reasonable to expect that the increase in new capital IT projects would drive the increase in the O&M expense for Information Technology-Investments.

On page 19 of his direct testimony, Mr. Tolonen shows the cumulative IT capital expenditures from 2014 to 2021. The percent increase in cumulative capital expenditures from 2019 to 2021 is 25% ($747 million vs. $598 million). The result of applying this rate of growth to the actual O&M expense for 2019 is a projected amount of expense for 2021 of $13.7 million.[39] This amount is $8.2 million lower than the O&M expense amount of $21.9 million forecasted by the Company for the projected test year.

The Company's forecasted O&M expense of $21.9 million in this area is excessive and unreasonable. Therefore, I recommend that the Commission remove the amount of $8.2 million from the Company's O&M forecasted amount.

<u>I. Info Technology Talent Enablement</u>

Q. PLEASE EXPLAIN YOUR RECOMMENDED REDUCTION OF O&M EXPENSE RELATED TO WORKFORCE CONNECT – TALENT ENABLEMENT?

[38] Christopher Varvatos in Case U-20650 direct testimony at page 19.
[39] 2019 expense amount of $10,936,000 x 1.25 = $13,670,000.

A. Workforce Connect – Talent Enablement is a Human Resources system described on pages 16 and 17 of witness Gaston's testimony. The Company plans to implement this system and have it operational at some point in the future. Ms. Gaston states that the Company currently uses the SAP Human Capital Module and that this SAP module will no longer be supported after 2025.

In addition, witness Gaston believes that significant new benefits will be realized from the new system. She describes these on page 16 of her testimony. However, she provides no financial quantification related to these benefits, some of which she believes will drive higher customer satisfaction levels.

Ms. Gaston does not indicate in her testimony that the SAP system is faulty or unworkable at this point. The Company has not made a compelling case that this expense is critically necessary for the projected test year. Given other pressing priorities with infrastructure replacement in other aspects of the Company's business, this expense should be rejected.

I recommend that the Commission reduce the O&M expense in this case by $1.4 million related to this project.

J. Info Technology – Other Expense

Q. PLEASE EXPLAIN WHAT OTHER ADJUSTMENTS YOU HAVE INCLUDED FOR INFORMATION TECHNOLOGY EXPENSE.

A. In my analysis of capital expenditures for IT projects, I identified certain projects that should be removed from the Company's forecasted capital spending. Along with the forecasted capital expenditures, the Company also forecasted O&M expense of $0.6 million for The Dashboard and Website projects, and $1.3 million for the Bill Design, MIMO and On Bill Financing projects. I recommend that the O&M expense pertaining to those projects also be removed for the reasons provided above.

K. Incentive Compensation Expense

Through the testimony of witnesses Amy Conrad and Michael Stuart, the Company has proposed to recover in rates nearly $5.2 million of short-term incentive compensation.[40] In the following pages of my testimony, I will analyze the Company proposal to include in rates the cost of this incentive compensation and the alleged benefits to customers provided by Mr. Stuart in his testimony

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S SHORT-TERM INCENTIVE COMPENSATION PLAN.

A. The Company has a short-term incentive compensation plan for officers and a slightly different plan for non-officer employees. The Company refers to each of these plans as the Employee Incentive Compensation Plan (EICP).

[40] Exhibit A-57 (AMC-3).

The major components of the EICP for non-officer employees are shown in Exhibit A-32 (AMC-1). Fifty percent (50%) of the target award is based on achieving 9 performance measures related to eliminating vintage services, employee safety, electricity service reliability, customer service delivery and customer experience, as well as new goals for cyber safety, generation customer value and compression availability as of 2018[41]. To achieve 100% payout of this grouping, the Company needs to only achieve 6 of the 9 performance measures. The other 50% of the target award is based on achieving earnings per share and operating cash flow goals of CMS Energy. The two items have a weight of 70% for earnings per share and 30% for operating cash flow.

This 50/50 combination of operating and financial measures started in 2012. In 2010 and 2011, the calculation of the non-officer EICP was based solely on achieving operating performance measures. The requirement to achieve 100% payout of target was also stricter with accomplishment of 9 measures out of 11 needed. The Company then adjusted this percentage based on the percent payout of the officers' EICP. Non-officer employees have received the following percentage payout of the target amount in recent years: 100% in 2009, 143% in 2010, zero in 2011, 115% in 2012, 118% in 2013, 125% in 2014, 123% in 2015 and 133% in 2016.[42] More recently, the Company achieved a 120% level in 2017 (operational goals) and overall payout level results of 123% and 111% in 2018 and 2019.[43]

[41] More recently, "Gas Flow Deliverability" has replaced the former metric "Compression Availability".
[42] CECo response discovery request AG-CE-252 partial by Mr. Shirkey in U-20322.
[43] See Discovery Response from Case U-20650 AG-CE-182, attachment 1.

The only year in the past nine years where a bonus payout was not made to non-officer employees was in 2011 when only 6 of the 11 operating measures were achieved.

For the officers' EICP, the target payout is based almost entirely on earnings per share and operating cash flow. However, the percent payout can be adjusted up or down depending on whether or not there is a payout related to the operating measures.

In forecasting the amount of EICP expense of $5.3 million included in the forecasted test year, the Company has assumed that a 100% payout for both the officer and non-officer EICP will occur.

Q. WHAT IS YOUR ASSESSMENT OF THE PERFORMANCE MEASURES INCLUDED IN THE 2019 EICP?

A. The 2019 performance measures are substantially the same as the 2018 performance measures. However, between 2017 and 2018 the Company retained or modified seven prior performance measures: Generation Reliability, Public Safety (now Vintage Services Eliminated), Employee Safety, Distribution Reliability, and three goals related to Customer Satisfaction. It replaced the other measures from 2017 with Cyber Safety and Compression Availability. I will discuss my concerns with some of these measures and specifically the ease or difficulty in achieving them. The 2019 performance measures are shown in Exhibit A-55 (AMC-1).

Q. WHAT IS YOUR OVERALL ASSESSMENT OF BOTH THE OFFICER AND NON-OFFICER EICP?

A. Generally, the Company's short-term incentive plans are too heavily weighted toward financial measures that mostly benefit shareholders and not customers.

Half of the non-officer employee EICP is based on achieving the earnings and cash flow goals of CMS Energy. For the officers' EICP, Ms. Conrad points out the importance of the financial goals on page 22 of her direct testimony where with respect to 2020 she states "I anticipate that for officers, the attainment of the financial measures will again be a threshold component with operational goals as a modifier."

As such, the officer group that sets the direction of the Company is far too focused on financial results. Customers do not directly benefit from shareholders achieving a higher return on their investment. Although the Company has argued in the past that happy investors will be more attracted to the Company debt and common stock issues and therefore provide a lower cost of capital, it has not offered direct proof to support this argument. The argument is particularly hollow since the Company does not issue common stock directly to public shareholders. Later in my testimony, I will discuss in more detail the customer benefits put forth by Mr. Stuart.

Q. DO YOU SEE ANY OTHER PROBLEMS WITH THE MEASURES INCLUDED IN THE EICP?

A. Yes. I see considerable duplication in many of the measures. For example, in the customer service area, the Company has three measures: Customer Experience Index, and two measures related to on time delivery of services or delivery within the target window. Performance in one measure is likely to affect the other two. For example, if the Company does a good job in delivering services by turning on gas and electric service this good performance will likely result in high scores also in the customer satisfaction surveys. In the financial measures, the operating cash flow is directly linked to earnings, the primary additions being depreciation & amortization expense and deferred taxes. So, if earnings per share go up, it is most likely that operating cash flow will also go up. Given that the payout is based on achieving a certain number of performance measures, the duplication makes it more likely that the targeted level will be achieved.

Another concern is the low threshold to achieve a payout under the EICP. Only 4 of the 9 operating measures, or less than 50%, need to be achieved for employees to get at least a 50% payout from this grouping of measures. Accomplishing less than half of the goals reflects sub-standard performance not worthy of any payout. This is a very generous incentive plan that is not directly connected with achieving superior customer benefits before making threshold incentive payouts.

Additionally, the fact that the performance measures use CMS Energy financial information and comingle electric and gas business measures is a concern. Although the Company is a combined gas and electric utility and makes up 95% of CMS Energy, appropriate cost segregation is required to avoid having electric customers subsidize other businesses, particularly non-utility operations.

Lastly, the Company has stated that it continues to pay salary increases each year of approximately 3% and has also included such an increase in the test year O&M expenses for all employee labor costs. On top of this, nearly all officers and other employees have received bonus payments almost every year from 2009 to 2019.

Q. PLEASE BRIEFLY SUMMARIZE AND PROVIDE YOUR ASSESSMENT OF THE CUSTOMER BENEFITS PRESENTED BY THE COMPANY TO JUSTIFY RECOVERY OF INCENTIVE COMPENSATION COSTS.

A. In his testimony, Mr. Stuart attempts to quantify certain benefits related to the operating performance measures that are part of the EICP. First, related to Employee Safety, Mr. Stuart states on page 3 of his testimony that the Company has achieved "… $4.4 million of annual direct savings, and $7.4 million of annual total savings that accrue to the benefit of the customer."

Also, on page 4 of his direct testimony, Mr. Stuart indicates that the Company is saving $17 million per year due to distribution reliability based on the Berkley Labs cost per outage minute data.

The problem with these alleged savings is that performance trends in these areas have reversed recently. For example, safety incidents have increased some 32% in the Company's gas business and 87% in the electric business (2018 vs. 2017).[44]

In addition, more recent data shows that the Distribution Reliability statistics show an increase in the SAIDI from 168 in 2014 to 235 in 2019.[45] Discovery request AG-CE-182 from case U-20650 shows that these two areas did not meet target levels in 2019 again. Therefore, this more recent information shows that, despite the incentives of the EICP, certain key measures are moving in the wrong direction.

I will point out that Mr. Stuart did not submit any exhibits to support his stated cost savings and that most of the cost savings relate to the entire company and only in some cases exclusively to the electric business. Moreover, benchmarking current performance relative to 2006 levels ignores the more recent reversal in these key statistics noted above.

After analyzing the cost savings presented by Mr. Stuart, it becomes obvious that the claimed financial benefits are highly inflated and often stale. More importantly, most of the savings the Company claims relate to what was achieved many years ago, but the Company still wants to claim credit to justify the cost of its incentive compensation for the projected test year.

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[44] See U-20322 AG-CE-265

[45] Richard Blumenstock direct testimony at page 27.

Mr. Stuart also points to potential annual savings of $242 million since 2006 for supposedly keeping O&M expenses below the rate of inflation.[46] These are not real savings but simply a "what-if" exercise. The claim of keeping O&M costs below the rate of inflation rings hollow when in this rate case filing the Company is requesting that customer rates include O&M cost increases reflecting payroll increases of more than 3%. In fact, O&M expenses are projected by the Company to increase by $110.7 million or 19% from 2018 to the end of the 2021 projected test year.[47] Clearly, customers are not benefiting from any O&M cost decreases in this case, real or otherwise.

As an additional point, with the revamping of the operating measures that the Company made between 2017 and 2018, it is not possible to assess yet what if any real financial benefits will accrue to customers from those new measures.

In summary, the purported cost savings to customers are questionable at best, and not sufficiently supported or objectively determined to justify any level of incentive compensation.

Q. WHAT CONCLUSIONS AND RECOMMENDATIONS HAVE YOU REACHED WITH REGARD TO RECOVERY OF INCENTIVE COMPENSATION COSTS IN RATES?

[46] Michael Stuart direct testimony at page 5.
[47] Exhibit A-13 (JRC-51), Schedule C-5.

A. As discussed above, the focus of the short-term incentive compensation plans is overwhelmingly directed at creating shareholder value, not customer benefits and the officer group that directs the day-to-day operations is only minimally incentivized to meet operational goals. Certain design flaws with the EICP tend to reward mediocre performance and diminish any real customer benefits. Incentive compensation should be paid for exceptional performance, at least to pass the test of cost recovery in rates. Performance that is ordinary and achieves basic goals and efficient operations is paid for in base salaries.

Both management and other employees have received large annual merit salary increases since at least 2009. The Company argues that it must pay a competitive compensation package to retain talented management and employees. Although that may be the case, it does not mean that customers should pay for all or most of that expense. Shareholders also significantly benefit from talented management, perhaps even more so than customers. Customers are paying for higher base pay each year. Shareholders can share the burden by paying for the incentive compensation that disproportionally favors their interests.

Therefore, I recommend that the entire $5.2 million of incentive compensation costs included in the forecasted test year O&M expense should be removed and disallowed.

Q. IN ITS ORDER IN CASE NO. U-20322 (THE MOST RECENT FULLY LITIGATED CASE FOR CONSUMERS ENERGY), THE COMMISSION ALLOWED THE

COMPANY TO RECOVER THE SHORT-TERM INCENTIVE COMPENSATION EXPENSE RELATED TO ONLY ACHIEVING OPERATING GOALS. WHAT IS YOUR VIEW?

A. In my opinion, the Company did not make a sufficiently compelling case to justify recovery of the proposed incentive compensation costs in Case No. U-20322. This is also true in this rate case.

However, if the Commission is persuaded that the Company achieved some limited level of operating benefits by a preponderance of evidence not contradicted by my testimony, then the amount of incentive pay that should be granted in rates should not be any more than the $880,875 for meeting the basic threshold level of performance, and shown in the Company's discovery response AG-CE-603, which is included in Exhibit AG-1.68.

L. Demand Response – O&M Expense

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO O&M EXPENSE FOR THE DEMAND RESPONSE PROGRAM.

A. In the Capital Expenditures section of my testimony, I present an analysis of the DR program. The conclusion of that analysis was a recommendation that the Commission disallow $18,921,000 of O&M expense from the Company's projected test year. I reiterate that recommendation here.

M. O&M Adjustments - Summary

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO O&M EXPENSE.

A. Operations and maintenance expenses represent a large part of the Company's cost structure. My analysis of the expense level proposed by the Company has shown that in the following areas these expenses are excessive or not needed and should be removed.

Summary of O&M Expense Reductions	Amount ($million)
Electric Distribution	$ 31.7
Line Clearing	16.0
Power Generation	6.9
Uncollectible Accounts Expense	1.2
Injuries and Damages	0.7
Corporate Expense	5.9
Health Care Costs	1.0
Information Technology	11.5
Incentive Compensation	5.2
Demand Response Program	18.9
Total	$ 99.0

As such, I recommend that the Commission reduce the amount of total O&M costs proposed by the Company by $99.0 million and reduce the revenue deficiency accordingly. Exhibit AG-1.55 provides further details.

VII. Depreciation Expense

Q. PLEASE DISCUSS THE DEPRECIATION EXPENSE ADJUSTMENT THAT YOU PROPOSE.

A. In Exhibit AG-1.42, I have identified the adjustments to be made to the Company's proposed capital expenditures. Those reductions lower the amount of depreciation expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in depreciation expense of $ 12.4 million. I recommend that the Commission reduce the Company's depreciation expense by this amount for the projected test year.

VIII. Service Restoration Deferred Accounting Mechanism

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL WITH REGARD TO THE DEFERRED RECOVERY MECHANISM FOR SERVICE RESTORATION COSTS.

A. Beginning on page 20 of her direct testimony, Ms. Houtz describes the Company's proposal to defer service restoration costs above a certain threshold and recover them in a subsequent rate case. Ms. Houtz proposes to establish service restoration expense of $65 million in the revenue requirement in this rate case and to establish an accounting deferral mechanism for any service restoration expense incurred above $70 million.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S DEFERRAL PROPOSAL?

A. The proposed deferral mechanism is not necessary and should be rejected by the Commission. The $65 million level of expense proposed by the Company to be included in rates is higher than any amount of expense incurred by the Company during the past 10 years, other than 2019. Although 2019 was an unusual year with service restoration expense reaching $92 million, the next highest expense amount in the past 10 years was $54.2 million in 2011. Exhibit AG-1.69 includes this information provided by the Company in response to discovery.

Therefore, the $65 million expense level and $70 million threshold levels are set significantly above typical average expense levels. The Company's proposed mechanism is a one-way mechanism that would allow the Company to recover amounts incurred above $70 million but would not allow customers to get the benefit of actual expenses levels below $65 million.

It is also noteworthy to point out that during the past five years, the Company has capitalized service restoration costs of between $63 million to $98 million annually for a total amount of $372 million over the five-year period from 2015 to 2019. These amounts are in addition to the O&M expense amounts and have allowed the Company to recover those costs in their entirety. Exhibit AG-1.69 also includes this information.

IX. Karn 1& 2 Retention Cost Deferral & Recovery

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL TO ESTABLISH A DEFERRED ACCOUNTING MECHANISM TO RECOVER EMPLOYEE RETENTION AND SEPARATION EXPENSES FOR THE RETIREMENT OF THE KARN 1 AND 2 GENERATING UNITS.

A. Beginning on page 5 of his direct testimony, Mr. Harry proposes the deferral of $27.4 million of retention bonus and severance payments to be paid to several employees at the Karn power plant during 2020 and 2023. The proposal is for these costs to be amortized from 2021 through 2039. The Company has already included $7.4 million in O&M expense in the projected test year pertaining to those expenses in the filed rate. The Company's deferral proposal would remove those expenses from the revenue requirement for 2021 and replace them with the amortization expense. Exhibit A-66 (DLH-1) shows the costs to be paid between 2020 and 2023, and the proposed amortization schedule.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION?

A. The Company already paid $5.9 million in retention costs in 2019, which it has expensed. It will incur an additional $13 million in 2020 which it will expense absent the establishment of a deferred accounting mechanism. By the end of 2020, the Company will have spent and expensed $18.9 million, or 57%, out of a total forecasted amount of $33.3

million from 2019 to 2023. It makes little sense to recapture expenses from 2020 and amortize them over future years.

Furthermore, the deferral and amortization of these cost over the next 18 years increases costs to customers in future years as the Company would include the unrecovered amount in working capital and earn a return on those costs.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission reject the Company's proposed deferred accounting mechanism for the Karn retention and severance costs.

X. CVR Shared Savings Proposal

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL FOR A SHARED SAVINGS OF FINANCIAL BENEFITS FROM THE CONSERVATION VOLTAGE REDUCTION (CVR) PROGRAM.

A. In his direct testimony, Company witness Michael Delaney discusses the Company's CVR program and a sharing of cost savings between the Company and customers that would be achieved form the program. Exhibit A-58 (MJD-1) summarizes the key information about the CVR program. According to the Company, the program would entail $16.3 million of O&M expense during the five-year period from 2021 to 2025.

During this same period the Company would make capital investments of $65.1 million to purchase and install equipment required to achieve the targeted voltage reduction and power savings. The revenue requirement that the Company would collect over the five-year period from capital investments and recovery of O&M expense is forecasted at $8.3 million.

According to Exhibit A-58, the Company would be able to achieve 80 MW of capacity reduction and reduce annual energy consumption by 184,491 MWh by the year 2025. The Company has quantified the avoided costs at $61.9 million during the five-year period.

In addition to receiving the revenue requirement of $8.3 million during the five-year period, the Company has proposed to share in 15% of the cost savings and earn an additional $8.0 million.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S DEFERRAL PROPOSAL?

A. The shared savings proposal is not necessary and should be rejected by the Commission for several reasons. First, CVR and the accompanying Volt-Var Optimization (VVO) are at their foundation means to improve the quality of power delivered to customers.

In the Company's IRP case in 2018, Company witness Mark Ortiz stated that Standard ANSI C84.1, which is the American National Standard for Electric Power Systems and Equipment for Voltage Ratings, specifies the steady-state voltage tolerances for an electrical power system. The standard divides voltages into two ranges. Range A is the optimal voltage range. Range B is acceptable, but not optimal. The target for CVR operation is the lower half of Range A (114V-120V) rather than the upper half of Range A (120V-126V). By providing energy in the lower range, the Company is reducing overall energy usage.[48]

Mr. Ortiz also stated that CVR technologies have been used for decades by other utilities in varying degrees. With improvements in technologies, CVR and VVO have become more viable solutions for many utilities.[49] Therefore, with the improvement in technology, customers are receiving the appropriate voltage they need and also good power quality. The Company should not receive an incentive for delivering good quality power. This is part of the basic service that a utility should provide when customers purchase power.

Second, the fact that CVR reduces power consumption for customers, and also reduces generating capacity, means that currently and in the past customers were receiving more voltage than necessary and were billed for more power costs than they should have been. CVR simply corrects a problem that has been endemic to the Company's system. The Company should not receive shared savings, or an incentive, for correcting a shortcoming with the current delivery of energy.

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[48] MPSC Case No. U-20165, Mark Ortiz direct testimony at page 4
[49] *Id*.

Third, the Company will make capital investments in order to install the necessary equipment to be able to achieve the voltage reduction. The Company will earn a return on those investments. It makes no sense to duplicate that return with the additional sharing of cost savings. The Company's premise that it has the option of investing in additional power plants versus CVR equipment is a false premise. In either case, the Company gets to earn a return on those capital investments and should only invest in facilities that are necessary to serve customers.

Fourth, the Company compares the CVR to the Energy Waste Reduction (EWR) program where it gets to earn an annual incentive for promoting energy conservation. This is a false strawman. The Company loses some sales and revenue when it effectively implements the EWR program. However, the EWR does not require the Company to make capital investments as is the case with the CVR program. Therefore, the CVR program provides an incentive to the Company to earn a return on capital investments that does not exist with the EWR. The fact the CVR may provide both a capacity and energy reduction benefit to customers from the capital investments does not mean that an additional incentive or sharing of cost savings is necessary.

Fifth, under the program the Company will be recovering the O&M expenses and costs pertaining to the capital expenditure. This means that customers bear the full risk of the program if it is not successful and does not generate sufficient savings. While the Company wants to share in the upside of the program, the sharing proposal does not impute any cost on the Company on the downside if the program is not successful. This would be an unbalanced sharing mechanism.

Sixth, the measurement of achieved power savings and capacity savings will be complex to calculate and difficult to validate. On page 14 of his testimony, Mr. Delaney gives a very brief glimpse of the method that the Company would use. Responses to several discovery requests show the complexity and assumptions that would need to be made to arrive at an approximation of the power savings, much less the theoretical capacity savings. The complexity can be assessed by reviewing the Company response to the discovery responses included in Exhibit AG-1.70.

Q. WHAT IS YOUR RECOMMENDATION?

A. For the reasons discussed above, I recommend that the Commission reject the Company's proposal to share in the CVR program savings. Those savings should accrue 100% to customers.

XI. Adjustments To Revenue Deficiency

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

A. Exhibit AG-1.71 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $20.7 million, which is a reduction of $223.6 million from the Company's requested level of $244.3 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $20.7 million.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

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

Experience and Qualifications of Sebastian Coppola

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

EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for nearly 20 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

ENERGY INDUSTRY EXPERIENCE

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

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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, multi-year rate plans and incentive ratemaking, and other regulatory matters.

Experience and Qualifications of Sebastian Coppola

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

Mr. Coppola 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, Washington Gas, 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

Experience and Qualifications of Sebastian Coppola

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.

Experience and Qualifications
of Sebastian Coppola

- **Specific Regulatory Proceedings And Related Experience:**
  - Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
  - Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
  - Filed testimony on behalf of the Michigan Attorney General in DTE Gas (DTE Gas) 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
  - Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
  - Filed testimony on behalf of the Michigan Attorney General in CECo 2018-2019 GCR reconciliation case U-20209.
  - Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2018-2019 GCR reconciliation case U-20215.
  - Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
  - Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2018 PSCR Reconciliation in case U-20203.
  - Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.
  - Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation

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

- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric (DTEE) 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.
- 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.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 gas rate Case U-18424 on several issues, including revenue,

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operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.

- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and

convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.

- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CECo Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.

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- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CECo Gas Choice and End-User Transportation tariff changes case U-17900.
- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.
- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CECo's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2012-2013 GCR Reconciliation case U-16924-R.

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- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CECo's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.
- Filed testimony in MichCon's 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling

mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.

- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors' compensation in the 2012 Avista general rate case.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio's power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation's 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo's electric business Pilot Revenue Decoupling Mechanism in case U-16566.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.
- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.

Experience and Qualifications
of Sebastian Coppola

- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.
- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the “Massachusetts Formula” at MichCon and at SEMCO in 1975 and 2000.

Experience and Qualifications of Sebastian Coppola

- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.
- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

EDUCATIONAL BACKGROUND

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

Corporate Analytics

Question:

30. Refer to page 55, lines 8-9, of Mr. Blumenstock's direct testimony. Please provide a list of projects with related dollar amounts that make up the total capital spending amount for each year 2020 and 2021, and identify which projects have a customer-signed agreement in place.

Response:

The requested information is provided in Attachment 1 to this discovery response.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 27, 2020

				20697-AG-CE-962
				Attachment 1
		Projected 2020	Projected 2021	Signed Agreement in Place
Sub-Program	**Project Description, Line, Substation, or Location**	**Spending**	**Spending**	**Yes or No**
New Business				
HVD Strategic Customers New Business	New 1.3 mile 138 kV line #1 to connect to a new dedicated customer substation in south-west Michigan	640	1,800	Yes
	New 1.3 mile 138 kV line #2 to connect to a new dedicated customer substation in south-west Michigan	640	1,800	Yes
	New 138 kV dedicated customer substation in south-west Michigan	3,680	6,000	Yes
	Relocate Cooper 46kV Line to accomomdate new 138 kV line to new dedicated customer substation in south-west Michigan		143	Yes
	Relocate Ampersee 46kV Line to accomomdate new 138 kV line to new dedicated customer substation in south-west Michigan		98	Yes
	New 138 kV dedicated customer substation in north-west Michigan	894	5,550	Yes
	Capacity upgrade at existing 46 kV dedicated customer substation in south-west Michigan	96		Yes
	Capacity upgrade at existing 46 kV dedicated customer substation in north-west Michigan	1,181		Yes
	New 138 kV dedicated customer substation in mid-Michigan	1,176		Yes
	New 0.1 mile 138 kV line to connect to a new dedicated customer substation in mid-Michigan	88		Yes
	Two new 46 kV air break switches and 46 kV line to increase reliability and accommodate/coordinate with retirement/removal of a dedicated customer substation in south-east Michigan	352		N/A*
	Replacement of obsolete dedicated customer power quality monitoring modems	80		N/A*
	Installation of relaying/protective equipment to bring up to standard two dedicated substations in mid-Michigan	288		N/A*
	Additional projects to be identified	2,999	1,891	No
	HVD Strategic Customers New Business Total	**12,114**	**17,281**	
	Work is being done in this sub-program not as part of a specific agreement, but to support program work, accommodate standards, support retirements/removals, etc.			

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Page **1** of **1**

Question:

37. Refer to Figure 27 on page 78 of Mr. Blumenstock's direct testimony. Please provide a revised table in Excel with actual 2014 to 2019, and forecasted 2019, 2020, 2021 information. Identify on separate lines the number of units and dollar amounts that pertain to programs reclassified to Rehabilitation.

Response:

The requested information is provided in Attachment 1 to this discovery response. Service restoration orders and streetlight failures are reactive investment categories, and were reactive investment categories over the entire period represented in Attachment 1, so no spending or units in this area pertain to activity that has been reclassified to Rehabilitation.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 27, 2020

20697-AG-CE-969
Attachment 1

		Actual						Projected	
		2014	2015	2016	2017	2018	2019	2020	2021
Service Restoration Orders	$000s	$ 46,361	$ 74,380	$ 64,326	$ 81,928	$ 62,594	$ 85,532	$ 55,320	$ 63,045
	Units	20,731	18,878	26,807	38,056	31,190	20,292	17,845	20,145
Streetlight Failures	$000s	$ 1,315	$ 1,771	$ 2,535	$ 2,580	$ 3,708	$ 10,188	$ 12,640	$ 15,493
	Units	3,592	2,339	4,131	5,039	7,977	16,103	16,072	19,700

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY

Exhibit AG-1.3
Case No: U-20697
June 24, 2020

Calculation of Service Restoration and Street Lights - Capital Expenditures Disallowanced

			Actual						Projected	
Line #			2014	2015	2016	2017	2018	2019	2020	2021
1		$000s	$ 46,361	$ 74,380	$ 64,326	$ 81,928	$ 62,594	$ 85,532	$ 55,320	$ 63,045
2	**Service Restoration Orders**	Units	20,731	18,878	26,807	38,056	31,190	20,292	17,845	20,145
3		Unit Cost	$ 2.236	$ 3.940	$ 2.400	$ 2.153	$ 2.007	$ 4.215	$ 3.100	$ 3.130
4										
5	2017 to 2019 Average	Unit Cost						$ 2.792	$ 2.792	$ 2.792
6	Forecasted	Units							17,845	20,145
7	Forecasted	Cost							$ 49,823	$ 56,245
8	**Variance from Company Forecast**								**$ (5,497)**	**$ (6,800)**
9										
10										
11		$000s	$ 1,315	$ 1,771	$ 2,535	$ 2,580	$ 3,708	$ 10,188	$ 12,640	$ 15,493
12	**Streetlight Failures**	Units	3,592	2,339	4,131	5,039	7,977	16,103	16,072	19,700
13		Unit Cost	$ 0.366	$ 0.757	$ 0.614	$ 0.512	$ 0.465	$ 0.633	$ 0.786	$ 0.786
14										
15	2017 to 2019 Average	Unit Cost						$ 0.537	$ 0.537	$ 0.537
16	Forecasted	Units							16,072	19,700
17	Forecatsed	Cost							$ 8,631	$ 10,579
18	**Variance from Company Forecast**								**$ (4,009)**	**$ (4,914)**

Source:
Exhibit AG-1.2 (20697-AG-CE-969)
Attachment 1

Question:

43. Refer to page 92, lines 15-22, of Mr. Blumenstock's direct testimony.

a. Which number was used to forecast capital spending for 2020 and 2021, 650 or 700?

b. How many were replaced as part of Demand Failures program each year from 2014 to 2019.

c. Why not replace these lights as they fail instead of accelerating their replacement through a special program?

d. Is the Company replacing the light fixture only or the entire suspension apparatus with a pole set-up and overhanging arm and fixture?

Response:

a. There is no forecast spending in the Streetlighting Center Suspension Replacement sub-program for 2020. For 2021, the Company's projected capital spending in this program was based on each replacement costing $7,500. While the Company plans to replace between 650 and 700 center suspension streetlights in 2021, the projected spending for 2021 is calculated based on 667 conversions.

b. As follows:
- 2014 through 2017: 0
- 2018: 8
- 2019: 42

c. As discussed on page 91, lines 12 through 22, and on page 93, lines 1 through 10, of my direct testimony, replacing a failed center suspension streetlight is a complex and time-consuming process. Waiting until a center suspension streetlight fails before converting it would result in extended failures; during the time it would take to convert the location, the area would lack illumination for a longer period than necessary. Proactive conversion will increase reliability, minimize outage response time for converted fixtures, and enhance crew and public safety.

d. The Company will replace the entire suspension apparatus with a pole set-up and bracketed arm.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 28, 2020

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Page **1** of **1**

Question:

3. Please break down capital expenditures for the investment categories listed in (a) – (c) below, from line 42 "Metro Failures" in Exhibit A-29 (RTB-2), for years 2017 – 2021.
a. Cable failure and replacement,
b. Transformer failure and replacement, and
c. Civil infrastructure failure and replacement.

Response:

The Company does not have data on capital expenditures at the investment category level for years 2017 and 2018 for the Metro Demand Failures sub-program, as these investment categories were not defined prior to 2019.

See response to discovery question 20697-ST-CE-383 for 2019 actuals.

Refer to the table below for years 2020 and 2021. As explained in the response to discovery question 20697-ST-CE-415, the Company has reduced its 2020 projected spending in Metro Demand Failures since this case was filed.

Investment Category Spending ($000)	**2020 Projected**	**2021 Projected**
Cable failure and replacement	$877	$629
Transformer failure and replacement	$49	$234
Civil infrastructure failure and replacement	$74	$2,237
Total	$1,000	$3,100

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 12, 2020

Question:

52. Refer to Figure 37 on page 125 of Mr. Blumenstock's direct testimony. Please provide a revised table in Excel with actual 2014 to 2019, and forecasted 2019, 2020, 2021 information.

Response:

The requested information is provided in Attachment 1 to this discovery response, with two additional categories not included in Figure 37 on page 125 of my direct testimony, "Other Projects and Expenditures" and "Muskegon River Marsh Line Relocate."

Because HVD Lines Reliability projects were not classified into investment categories before the Company's 2018 EDIIP report in Case No. U-20147, the Company has historical spending in this sub-program that does not fit into one of the existing investment categories. From 2014 through 2016, the dollar amounts in the "Other Projects and Expenditures" category represent expenditures and credits to the sub-program from projects that: 1) are types of work that do not fit into the stated Investment Categories, 2) expenditures and adjustments for projects that match an Investment Category but are accounted for in a year different than when the work was constructed, or 3) expenditures for projects that match an Investment Category where construction activities spanned multiple years and the unit was counted in another year (i.e. project started in 2014 and completed in 2015; the 2014 expenditures counted as "Other Projects and Expenditures" and the 2015 expenditures and unit were counted in the Investment Category in 2015 so the unit was not counted twice, one in each year, which could give the appearance of inflated numbers for the specified Investment Category).

The Muskegon River Marsh Line Relocate category refers to a project initially completed in the HVD Lines Reliability sub-program in 2014. The Cobb-Muskegon Heights 138 kV #1 and #2 lines, part of this project, were later reclassified as transmission in 2016, resulting in credits to the HVD Lines Reliability sub-program.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 28, 2020

20697-AG-CE-984
Attachment 1

Figure 37: Expanded
HVD Lines Reliability Investment Category
Expenditures and Units

	Actual												Forecast			
	2014		2015		2016		2017		2018		2019		2020		2021	
Investment Categories	**Capital**	**# of Units**	**Capital**	**# of Units**	**Capital**	**# of Units**	**Capital**	**# of Units**	**Capital**	**# of Units**	**Capital**	**# of Units**	**Capital**	**# of Units**	**Capital**	**# of Units**
Line Rebuilds	$ 12,971,991	30 miles	$ 6,785,021	40 miles	$ 9,885,346	14 miles	$ 5,925,814	38 miles	$ 19,460,975	24 miles	$ 31,448,329	73 miles	$ 9,886,000	25 miles	$ 46,406,000	72 miles
Pole Top Rehabilitations	$ -		$ 1,680,513	55 miles	$ 6,504,839	75 miles	$ 3,733,193	44 miles	$ 6,948,025	71 miles	$ 5,728,911	101 miles	$ 4,566,000	44 miles	$ 9,658,000	106 miles
Pole Replacements per pole insepection program	$ 11,877,148	680 poles	$ 5,696,348	506 poles	$ 20,669,065	1,076 poles	$ 9,058,654	723 poles	$ 16,055,028	725 poles	$ 10,207,770	489 poles	$ 9,656,000	450 poles	$ 17,614,000	890 poles
Other Projects and Expenditures	$ 393,308		$ 208,576		$ 884,075		$ -		$ -		$ -		$ -		$ -	
Muskegon River Marsh Line Relocate	$ 1,459,993	9 miles	$ 269,229		$ (118,532)		$ (2,378,049)	(4 miles)	$ -		$ -		$ -		$ -	
Switches (inc. SCADA additions)							$ 985,074	12 switches	$ 243,536	3 switches	$ 430,944	4 switches	$ 2,971,000	44 switches	$ 4,451,000	42 switches
Total	**$ 26,702,440**		**$ 14,639,688**		**$ 37,824,793**		**$ 17,324,686**		**$ 42,707,564**		**$ 47,815,954**		**$27,079,000**		**$ 78,129,000**	

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY

Calculation of HVD Lines Reliability Capital Expenditures Disallowances

Exhibit AG-1.7
Case No: U-20697
June 24, 2020

Line #		Actual						Forecast			
		2017		2018		2019		2020		2021	
1	**Investment Categories**	**Capital**	**# of Units**	**Capital**	**# of Units**	**Capital**	**# of Units**	**Capital**	**# of Units**	**Capital**	**# of Units**
2	**Line Rebuilds**	$ 5,925,814	38 miles	$ 19,460,975	24 miles	$ 31,448,329	73 miles	$ 9,886,000	25 miles	$ 46,406,000	72 miles
3	2017 - 2019 Average					$ 56,835,118	135				
4	2017 - 2019 Average Cost Per unit						$ 421,001			$ 421,001	72
5	**AG Forecasted Cost for 2021**									$ 30,312,063	
6	**Difference**									**$ (16,093,937)**	
7											
8	**Pole Top Rehabilitations**	$ 3,733,193	44 miles	$ 6,948,025	71 miles	$ 5,728,911	101 miles	$ 4,566,000	44 miles	$ 9,658,000	106 miles
9	2017 - 2019 Average					$ 16,410,129	216				
10	2017 - 2019 Average Cost Per unit						$ 75,973			$ 75,973	106
11	**AG Forecasted Cost for 2021**									$ 8,053,119	
12	**Difference**									**$ (1,604,881)**	
13											
14	Pole Replacements per pole insepection program	$ 9,058,654	723 poles	$ 16,055,028	725 poles	$ 10,207,770	489 poles	$ 9,656,000	450 poles	$ 17,614,000	890 poles
15	2017 - 2019 Average					$ 35,321,452	1937	$ 8,205,810			
16	2017 - 2019 Average Cost Per unit						$ 18,235			$ 18,235	890
17	**AG Forecasted Cost for 2021**									$ 16,229,268	
18	**Difference**									**$ (1,384,732)**	

Source:

Exhibit AG-1.6 (20697-AG-CE-984 Att 1)

U20697-AG-CE-986
Page **1** of **1**

Question:

54. Refer to Figure 40 on page 135 of Mr. Blumenstock's direct testimony. Please provide a revised table in Excel with actual 2014 to 2019, and forecasted 2019, 2020, 2021 information.

Response:

The requested information is provided in Attachment 1 to this discovery response.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 27, 2020

20697-AG-CE-986
Attachment 1

	2014		2015		2016		2017		2018		2019		2020		2021	
RELIABILITY Investment Categories	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects
New or rebuilt substations	$1,480,904	3	$2,771,382	2	$3,154,925	2	$ -	0	$ 1,837,133	2	$ 6,471,136	6	$ 2,500,000	6	$ 5,140,000	3
Mobile substations	$0	0	$2,060,354	1	$2,498,377	3	$ 3,553,924	2	$ 73,322	2	$ 709,830	1	$ 6,300,000	4	$ 3,360,000	1
Animal mitigation	$1,727,824	31	$2,142,342	70	$2,238,743	79	$ 4,288,797	120	$ 1,927,262	26	$ 2,276,747	42	$ 1,900,000	20	$ 4,002,000	40
Transformer replacements	$0	0	$0	0	$0	0	$ -	0	$ 1,188,791	2	$ 300,160	1	$ -	0	$ 2,000,000	3
Regulator replacements	$385,538	6	$1,292,213	47	$772,037	40	$ 677,906	32	$ 827,048	36	$ 601,493	32	$ 400,000	16	$ 1,000,000	34
Other Projects and Charges	$3,185,339	86	$669,711	96	$2,471,415	137	$ 5,591,853	94	$ 4,344,336	65	$ 3,218,101	57	$ 400,000	10	$ -	0
Total	**$ 6,779,605**	**126**	**$ 8,936,002**	**216**	**$11,135,497**	**261**	**$14,112,479**	**248**	**$10,197,892**	**133**	**$13,577,467**	**139**	**$11,500,000**	**56**	**$15,502,000**	**81**

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY

Calculation of LVD Station Reliability Capital Expenditures Disallowances

Line #		2015		2016		2017		2018		2019		2020		2021	
1	RELIABILITY Investment Categories	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects	Capital	# of Projects
2	**Mobile substations**	$2,060,354	1	$2,498,377	3	$ 3,553,924	2	$ 73,322	2	$ 709,830	1	$ 6,300,000	4	$ 3,360,000	1
3	2015 - 2019 Average, excl. 2018									$ 8,822,484	7				
4	2017 - 2019 Average Cost Per unit									$ 1,260,355		$ 1,260,000		$ 1,260,000	
5	**AG Forecasted Cost for 2020 and 2021**											$ 5,040,000	4	$ 1,260,000	1
6	**Difference**											**$ (1,260,000)**		**$ (2,100,000)**	
7															
8	**Animal mitigation**	$2,142,342	70	$2,238,743	79	$ 4,288,797	120	$ 1,927,262	26	$ 2,276,747	42	$ 1,900,000	20	$ 4,002,000	40
9	2017 - 2019 Average									$ 8,492,806	188				
10	2017 - 2019 Average Cost Per unit									$ 45,174		$ 45,174		$ 45,174	
11	**AG Forecasted Cost for 2020 and 2021**											$ 903,490	20	$ 1,806,980	40
12	**Difference**											**$ (996,510)**		**$ (2,195,020)**	

Source:
Exhibit AG-1.8 (20697-AG-CE-986 Att 1)

Question:

57. Refer to Figure 38 on page 147 of Mr. Blumenstock's direct testimony. Please provide a revised table in Excel with actual 2014 to 2019, and forecasted 2019, 2020, 2021 information.

Response:

The requested information is provided in Attachment 1 to this discovery response.

Prior to 2018, costs were not always tracked in alignment with these investment categories. For example, in 2015 and 2017 the Company completed line sensor projects, but costs for these projects were not separately tracked in the line sensor investment category.

In 2017, the Company purchased regulator controllers late in the year, and installed them in 2018.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 28, 2020

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No: U-20697**
Consumers Energy Company | **Exhibit: AG-1.10**
June 24, 2020
CECo Response to AG-CE-989 |

																20697-AG-CE-989
																Attachment 1
	2014 (Actual)		2015 (Actual)		2016 (Actual)		2017 (Actual)		2018 (Actual)		2019 (Actual)		2020 (plan)		2021 (Plan)	
Investment Categories	Capital	# of Units	Capital	# of Units	Capital	# of Units	Capital	# of Units	Capital	# of Units	Capital	# of Units	Capital	# of Units	Capital	# of Units
Automation																
DSCADA & SCADA	$8,898,516	90	$5,735,140	31	$4,068,715	21	$8,834,830	65	$9,742,997	71	$10,580,116	42	$13,217,000	92	$21,542,000	118
ATR Loops	$0	0	$0	0	$685,060	5	$2,903,924	11	$6,999,644	4	$18,791,470	24	$14,644,000	26	$21,258,000	39
Line Sensors	$0	0	$0	18	$7,472	117	$0	32	$2,437,404	180	$1,549,692	605	$3,530,500	1100	$4,544,000	100
Regulator Controllers	$0	0	$0	0	$0	0	$200,764	0	$2,489,473	8	$8,185,349	302	$12,580,000	210	$13,077,000	393
Advanced Tech.																
ADMS	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$18,376,961	n/a	$17,900,000	n/a	$5,900,000	n/a
DERMS	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$1,208,710	n/a	$1,184,000	n/a
Grid Operation Analytics	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$748,000	n/a	$748,000	n/a
Grid Technologies	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$1,350,000	n/a

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY

Exhibit AG-1.11
Case No: U-20697
June 24, 2020

Calculation of Station Automation Capital Expenditures Disallowances

Line #		2017 (Actual)		2018 (Actual)		2019 (Actual)		2020 (plan)		2021 (Plan)	
1	Investment Categories	Capital	# of Units	Capital	# of Units	Capital	# of Units	Capital	# of Units	Capital	# of Units
2	**Automation**										
3	**Line Sensors**	$0	32	$2,437,404	180	$1,549,692	605	$3,530,500	1100	$4,544,000	100
4	2017 - 2019 Total					$3,987,096	817				
5	2017 - 2019 Average Unit Cost						$ 4,880			$4,880	
6	**AG Forecasted Cost for 2021**									$488,017	100
7	**Difference**									**(4,055,983)**	
8											
9	**Regulator Controllers**	$200,764	0	$2,489,473	8	$8,185,349	302	$12,580,000	210	$13,077,000	393
10	2017 - 2019 Total					$10,875,586	310				
11	2017 - 2019 Average Unit Cost						$ 35,083	$35,083			
12	**AG Forecasted Cost for 2021**							$7,367,332	210		
13	**Difference**							**-$5,212,668**			
14	**Advanced Tech.**										
15	**Grid Technologies**	$0	n/a	$0	n/a	$0	n/a	$0	n/a	**$1,350,000**	n/a

Source:

Exhibit AG-1.10 (20697-AG-CE-989 Att 1)

Question:

65. Refer to page 178, lines 1-13, of Mr. Blumenstock's direct testimony. Please provide the list of projects with related dollar amounts and explain on what basis you reached the conclusion that these projects pose an imminent threat of failure.

Response:

The list of projects with related dollar amounts was provided in Exhibit A-42 (RTB-15), page 22, lines 18 through 43 – as was stated on pages 184 and 185 of my direct testimony. Attachment 1 to this discovery response reproduces this information, with an additional column indicating the basis on which the Company reached its conclusions. Details about how the Company identifies projects in the LVD Substations Rehabilitation are provided on pages 179 through 182 of my direct testimony.

Additionally, as shown in Exhibit A-41 (RTB-14), lines 9, 16, and 17, further information on these projects was provided in workpaper WP-RTB-5, page 154 and pages 202 through 207.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 27, 2020

							20697-AG-CE-997
							Attachment 1
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line			**Projected 2021**				
No.	**Sub-Program**	**Project Description, Line, Substation, or Location**	**Test Year**	**Units**	**Unit Type**	**Investment Category**	**Basis**
1	LVD Substations Rehabilitation						
2		FAIRFIELD	800	2		AC Transformers	AC Transformer Replacement Program
3		DAVISON	1,200	2		AC Transformers	AC Transformer Replacement Program
4		METRO	800	2		AC Transformers	AC Transformer Replacement Program
5		NORTH KENT	600	1		AC Transformers	AC Transformer Replacement Program
6		ROSEWOOD	600	1		AC Transformers	AC Transformer Replacement Program
7		KINGSLEY	600	1		AC Transformers	AC Transformer Replacement Program
8		LINDEN	600	1		AC Transformers	AC Transformer Replacement Program
9		MERSON	600	1		AC Transformers	AC Transformer Replacement Program
10		SUTTONS BAY	600	1		AC Transformers	AC Transformer Replacement Program
11		FIFTEEN MILE ROAD	800	1		AC Transformers	AC Transformer Replacement Program
12		HALLS LAKE	600	1		AC Transformers	AC Transformer Replacement Program
13		INGHAM	600	1		AC Transformers	AC Transformer Replacement Program
14		MORLEY	600	1		AC Transformers	AC Transformer Replacement Program
15		BRICKER / Working Clearance Code	450	1		Equipment Replacements and Regulatory	Working Clearance Code Violations
16		GREENWOOD / Working Clearance Code	750	1		Equipment Replacements and Regulatory	Working Clearance Code Violations
17		HARING / Working Clearance Code	450	1		Equipment Replacements and Regulatory	Working Clearance Code Violations
18		ROEDEL ROAD / Working Clearance Code	450	1		Equipment Replacements and Regulatory	Working Clearance Code Violations
19		MILLERS POINT / Working Clearance Code	450	1		Equipment Replacements and Regulatory	Working Clearance Code Violations
20		STONEGATE / Working Clearance Code	450	1		Equipment Replacements and Regulatory	Working Clearance Code Violations
21		SARANAC / Obsolete Reclosers	75	6		Equipment Replacements and Regulatory	Obsolete Equipment Replacements
22		KENT CITY / Obsolete Reclosers	150	6		Equipment Replacements and Regulatory	Obsolete Equipment Replacements
23		LEELANAU / Obsolete Reclosers	100	6		Equipment Replacements and Regulatory	Obsolete Equipment Replacements
24		STEELCASE / Obsolete Reclosers-Switches-Fuses	375	16		Equipment Replacements and Regulatory	Obsolete Equipment Replacements
25		PELLSTON	600	1		Transformer Replacements (Imminent)	Dissolved Gas Analysis data
26		TUNNEL PARK	600	1		Transformer Replacements (Imminent)	Equipment degradation data
27		ARCADIA	600	1		Transformer Replacements (Imminent)	Dissolved Gas Analysis data
28		**LVD Substations Rehabilitation Total**	**14,500**				

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Page **1** of **1**

Question:

67. Refer to page 185, lines 4-5, of Mr. Blumenstock's direct testimony. If the three transformers pose an imminent threat of failure, why wait until 2021 to replace them? Why was this work not done in 2019 or 2020?

Response:

Please see discovery response 20697-AG-CE-997 for references to previously-provided information regarding these projects.

The Company balances project priorities, spare equipment inventory, system risk, customer reliability, mobile substation deployment, and Company resources when planning and executing its workplan. The following were primary considerations for placing the Pellston, Tunnel Park and Arcadia Substation transformer replacements in the workplan for 2021:

1. Based on transformer inventory numbers at the time of project identification, the Company decided to order new transformers for these projects to keep spare transformers available throughout 2020 in case of unplanned failures at other substations, and to use other existing transformers in inventory for the already-planned Allis Chalmers transformer replacements and other imminent failure projects scheduled ahead of Pellston, Tunnel Park and Arcadia. The Tunnel Park transformer will be received in late 2020 and the Pellston and Arcadia transformers will be received in 2021.
2. The Company's mobile substation fleet is fully allocated in 2020 for customer committed and program projects, Allis Chalmers transformer replacements and other imminent failure projects scheduled ahead of Pellston, Tunnel Park and Arcadia.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 27, 2020

Question:

68. Refer to Figure 48 on page 189 of Mr. Blumenstock's direct testimony. Please:

a. Provide a revised table in Excel with actual 2014 to 2019, and forecasted 2019, 2020, 2021 information.

b. Explain why the unit cost for Security assessment repairs is $120,140 ($25,830,000 / 215 units) for 2021 when the highest unit cost in Figure 49 is $15,400 for prior years. Explain also a similar problem with Imminent Rehabilitation between 2021 and prior years' unit costs in Figure 49.

Response:

a. Please see Attachment 1 to this discovery response.

b. The apparent difference in unit cost for security assessment repairs reflects the use of two different divisors. In Figure 48, the units for security assessment repairs are circuits. In Figure 49, the units for security assessment repairs are orders. This reflects a shift in how the Company budgets for these projects. For imminent rehabilitation projects, unit costs for 2021 are $2,890/order ($11,893,000/4,115), which is lower than the unit costs for imminent rehabilitation projects in Figure 49, so a "similar problem" does not exist for imminent rehabilitation projects.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 28, 2020

20697-AG-CE-1000
Attachment 1

		Actual						Projected	
		2014	2015	2016	2017	2018	2019	2020	2021
Imminent Rehabilitation	$000s	$ 44,539	$ 74,045	$ 60,141	$ 73,502	$ 91,163	$ 17,342	$ 10,117	$ 11,893
	Units (orders)	24,100	20,997	30,423	42,379	40,367	1,269	2,632	4,115
Security Assessment Repairs	$000s	$ 3,135	$ 2,106	$ 6,719	$ 11,006	$ 7,089	$ 5,061	$ 10,480	$ 25,830
	Units (see below)	223	220	515	716	512	69	134	215
		Units = Orders					Units = Circuits		

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY

Exhibit AG-1.14
Case No: U-20697
June 24, 2020

Calculation of LVDLines Rehab Capital Expenditures Disallowances

			Actual						Projected	
Line #			**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
		$000s	$ 44,539	$ 74,045	$ 60,141	$ 73,502	$ 91,163	$ 17,342	$ 10,117	$ 11,893
1	**Imminent Rehabilitation**	**Units (orders)**	24,100	20,997	30,423	42,379	40,367	1,269	2,632	4,115
2	2017 - 2019 Total	$000s						$ 182,007		
3	2017 - 2019 Total	Units (orders)						84,015		
4	2017 - 2019 Average Unit Cost							$ 2.166	$ 2.166	$ 2.166
5	**AG Forecasted Cost for 2021**								$ 5,701	$ 8,913
6	**Difference**								**(4,416)**	**(2,980)**
7										
8										
9		**$000s**	$ 3,135	$ 2,106	$ 6,719	$ 11,006	$ 7,089	$ 5,061	$ 10,480	$ 25,830
10	**Security Assessment Repairs**	**Units (see below)**	223	220	515	716	512	69	134	215
11	2019 Average Unit Cost							$ 73.348	$ 73.348	$ 73.348
12	**AG Forecasted Cost for 2021**								$ 9,829	$ 15,770
13	**Difference**								$ (651)	**$ (10,060)**

Source:

Exhibit AG-1.13 (20697-AG-CE-1000 Att 1)

U20697-ST-CE-419
Page **1** of **1**

Question:

50. Refer to Figure 59 on page 208 of Mr. Blumenstock's direct testimony, which shows HVD Lines and Substation Capacity investment category expenditures and projects for 2021. Please expand this table so that it shows capital expenditures for all of the listed investment categories, except "TBD", for 2017–2020. Provide actuals for 2019.

Response:

An expanded table is provided as Attachment 1 to this discovery response.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
April 24, 2020

20697-ST-CE-419
Attachment 1

Investment Categories	2017 Actual Capital	2017 # of Projects	2018 Actual Capital	2018 # of Projects	2019 Actual Capital	2019 # of Projects	2020 Projected Capital	2020 # of Projects	2021 Projected Capital	2021 # of Projects
Load carrying capabilities and voltage support	$2,751,000	7	$1,135,000	1	$6,720,000	6	$7,387,000	7	$2,955,000	4
New interconnections	$1,433,000	13	$2,317,000	8	$2,343,000	7	$2,113,000	18	$4,454,000	24
Improved functionality	$6,598,000	28	$5,181,000	17	$3,969,000	6	$5,171,000	20	$5,247,000	14
Coordination with Transmission	$1,269,000	5	$3,241,000	7	$3,816,000	5	$4,374,000	12	$2,429,000	4
Right of way procurement	$4,771,000	9	$4,671,000	8	$5,140,000	14	$2,456,000	22	$3,035,000	9
TBD									$2,084,000	
Total	**$16,823,000**	**62**	**$16,545,000**	**41**	**$21,989,000**	**38**	**$21,501,000**	**79**	**$20,203,000**	**55**

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Page **1** of **1**

Question:

11. Refer to page 223, lines 6-10, of Mr. Blumenstock's direct testimony. Please provide a list of solar projects with the most recent project timeline from start to completion of each project.

Response:

As stated in discovery responses 20697-ST-CE-428 and 20697-ST-CE-429, the Company has not yet identified the locations for these solar projects.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 4, 2020

U20697-ST-CE-430
Page **1** of **1**

Question:

61. Refer to Figure 63 on page 228 of Mr. Blumenstock's direct testimony, which shows tools investment category expenditures and units for 2021. Please expand this table so that it shows capital expenditures for the truck tool packages category and the other capital tool purchases category for 2017–2020. Provide actuals for 2019.

Response:

The requested information is provided below:

Investment Categories	**2017**	**2018**	**2019**	**2020**
Truck tool packages	$459,000	$1,321,000	$2,496,000	$2,736,000
Other capital tools	$1,444,000	$2,501,000	$1,588,000	$2,955,000
Total	$1,903,000	$3,822,000	$4,084,000	$5,691,000

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
April 24, 2020

Question:

12. Refer to Figure 54 on page 228 of Mr. Blumenstock's direct testimony. Please provide a revised table in Excel with actual information for 2014 to 2019, and forecasted 2019, 2020, 2021 information.

Response:

Note that, as state on page 228, line 10, of my direct testimony, the figure on page 228 should be labeled Figure 63.

The Company began separating truck tool packages as an investment category when these purchases began in 2016 (see page 227, line 17, of my direct testimony). Therefore, separate investment category data is not available for 2014 or 2015. The requested information for 2021 is provided in the figure on page 228 of my direct testimony. The requested spending breakdowns for 2017 through 2020 were already provided in discovery response 20697-ST-CE-430.

The Company's spending on truck tool packages for 2016 was $772,000.

The Company's truck tool package purchases for each year is as follows:

- 2016: 44
- 2017: 159
- 2018: 47
- 2019: 64
- 2020 (planned): 47

Truck tool packages are not one-size-fits-all, but vary depending on what type of truck is being outfitted. In 2016 and 2017, the Company's truck tool packages were smaller and less expensive on a unit basis than those in 2018 and later years.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 4, 2020

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY

Exhibit AG-1.18
Case No: U-20697
June 24, 2020

Calculation of Tool Capital Expenditures Disallowances

		Actual					
Line #		2017	2018	2019	2/3-Year Total [1]	2020	2021
1	**Truck Tool Packages**	$ 459,000	$ 1,321,000	$ 2,496,000	$ 3,817,000	$ 2,736,000	$ 2,118,000
2	Number of Packages	159	47	64	111	47	60
3	Average 2018/2019				$ 34,387		
4	AG Forecast				$ 34,387	$ 1,616,207	$ 2,063,243
5	**Difference**					**$ (1,119,793)**	$ (54,757)
6							
7	**Other Capital Tools**	$ 1,444,000	$ 2,501,000	$ 1,588,000		$ 2,955,000	$ 3,674,000
8	Average 2017-2019				$ 1,844,333		
9	AG Forecast				$ 1,844,333	$ 1,844,333	$ 1,844,333
10	**Difference**					**$ (1,110,667)**	**$ (1,829,667)**

Source: Exhibit AG-1.17.
(1) Truck Tool Packages calculated based on 2018-2019 average.

Question:

63. Refer to Figure 65 on page 233 of Mr. Blumenstock's direct testimony, which shows system control projects investment category expenditures and units for 2021. Please expand this table so that it shows capital expenditures for the four categories for 2017–2020. Provide actuals for 2019.

Response:

The requested information is provided below. Note that these investment categories were not necessarily in the System Control sub-program in each year, so the totals may not align with the totals shown in Exhibit A-29 (RTB-2), line 50. The Emergency Operations Center was not included in the figure on page 233 of my direct testimony, but is included in System Control projected spending. The Company is projecting less spending in 2020 than was presented in the initial filing in this case.

	2017	2018	2019	2020
HVD Operations Projects	$0	$212,437	$1,479,615	$718,531
HVD Remote Monitoring & Control	$1,110,126	$1,846,354	$2,405,000	$0
Operating Tech Enhancements	$0	$0	$69,533	$250,000
SCC & DCC Control Room Modifications	$420,800	$5,417	$667,950	$921,110
Emergency Operation Center	$0	$0	$0	$816,515
Total	$1,530,926	$2,064,208	$4,623,067	$2,706,156

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
April 24, 2020

U20697-AG-CE-1102
Page **1** of **1**

Question:

14. Refer to Figure 565 on page 233 of Mr. Blumenstock's direct testimony. Please provide a revised table in Excel with actual information for 2014 to 2019, and forecasted 2019, 2020, 2021 information.

Response:

As stated on page 233, line 15, of my direct testimony, the figure on page 233 should be labeled Figure 65.

Requested information regarding spending was provided for 2017 through 2020 in discovery response 20697-ST-CE-432. That information has been expanded below to include units. Information for 2021 is already provided in Figure 65 on page 233 of my direct testimony. As noted in discovery response 20697-ST-CE-432, the investment categories that are included in the System Control sub-program have varied in historical years. Consequently, the totals provided below may not align with the totals shown in Exhibit A-29 (RTB-2), line 50. Because of this historically varying nature of this sub-program, investment category data of the type presented in Figure 65 in my direct testimony is not available prior to 2017.

	Actuals						Projected	
	2017		2018		2019		2020	
Investment Categories	Capital	# of Units	Capital	# of Units	Capital	# of Units	Capital	# of Units
HVD Operations Projects			$212,437	4	$1,479,615	32	$718,531	22
HVD Remote M&C Cap	$911,472	49	$1,062,104	113	$2,298,079	95	$0	$0
Op Tech Enhancements					$69,533	2	$250,000	2
SCC & DCC Control Room Modifications	$420,800	4	$5,417	6	$667,950	3	$921,110	3
Emergency Operations Center							$816,515	1
Total	$1,332,272		$1,279,958		$4,515,177		$2,706,156	

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 4, 2020

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY

Exhibit AG-1.20
Case No: U-20697
June 24, 2020

Calculation of HVD System Remote Controls Capital Expenditures Disallowances

		Actual					
					3-Year		
Line #		**2017**	**2018**	**2019**	**Total**	**2020**	**2021**
1	**HVD System Controls**	$ 911,472	$ 1,062,104	$ 2,298,079	$ 4,271,655	$ -	$ 2,305,000
2	Number of Packages	49	113	95	257		62
3	Average 2018/2019				$ 16,621		
4	AG Forecast				$ 16,621		$ 1,030,516
5	**Difference**						**$ (1,274,484)**
6							

Source: Exhibit AG-1.19.

Question:

32. Refer to WP-RTB-5 for each of the following projects and answer the questions below with regard to each project:

Project 21-0003 beginning on page 2.

Project 21-0014 beginning on page 12.

Project 1028995535 beginning on page 22.

Project 1041254276 beginning on page 23.

Project 1045583485 beginning on page 30.

Project 2021-UINJ beginning on page 61.

Project 1041352540 beginning on page 63.

Project 17-0019A beginning on page 66.

Project 21-0024 beginning on page 75.

Project 21-0020 beginning on page 78.

Project 21-0022 beginning on page 82.

Project 21-0021 beginning on page 88.

Project 21-0019 beginning on page 110.

Project 21-0025 beginning on page 113.

Project 21-0040 beginning on page 117.

Project 21-0026 beginning on page 120.

Project 21-0015 beginning on page 151.

Project 21-0043 beginning on page 177.

Project 22-0003 beginning on page 183.

Project 22-0002 beginning on page 195.

Project 21-0005 beginning on page 202.

Project 21-0016 beginning on page 241.

Project 1041345703 beginning on page 259.

Project 1046415227 beginning on page 266.

Project 18-0025 beginning on page 279.

Project 21-0047 beginning on page 385

a. Some of the information in the project descriptions has been redacted. Please provide unredacted copies under the Protective Order and signed NDA certificates by the AG.

b. Some of the project documents show required approvals by different levels of management but do not show actual approval signatures and date of approval. Please provide a copy of the documents showing the approval signatures and date of approval by each approval level.

c. Some of the project documents show a Circuit Owner and System Engineer name, but no approval signatures by management and the date of approval.

Please provide a copy of the documents with the appropriate approval signature and date of signature approval.

d. If a subsequent project cost estimate was prepared after the conceptual project documents listed above, please provide the detailed project cost estimate showing cost components and forecasted spending levels by year with applicable approval signatures and dates for each project.

e. If not included in the documents in part (d) above, please provide the date and amount of budget authorization for each project, and the approval signature for the authorization.

f. Provide the amount of capital for each project included in this rate case by year from 2018 to 2021. If the amount in the rate case for the applicable years varies by more than 10% from the conceptual amount for the same period, please explain the reasons for the difference and provide justification for the variance.

g. Provide the actual amount spent on each project for each year 2018 and 2019, and for the first four months of 2020.

h. The projects included in WP-RTB-5 appear to be mostly projects scheduled for 2021. Please provide the conceptual approval documents for 2019 and 2020 projects of $1 million and greater. Provide also the s

<u>Response:</u>

<u>Objection of Counsel:</u> Consumers Energy Company objects to this discovery request because it is unduly burdensome and overly broad. The burdens of providing a response to portion of this request are not proportional to the needs of this case. The Company also objects to this request to the extent that it seeks customer information which is required to be protected pursuant to the rules contained in the Company's Rate Book for Electric Service, as approved by the Michigan Public Service Commission. Subject to that objection, and without waiving it, the Company provides the following response:

a. The redacted information in Confidential workpaper WP-RTB-5 is generally customer-identifying information, which the Company is not able to provide.

b. The Company followed its internal approval process for these projects, and all of these projects have received all necessary approvals and signatures.

c. The Company followed its internal approval process for these projects, and all of these projects have received all necessary approvals and signatures.

d. The costs provided in the documents in Confidential workpaper WP-RTB-5 are the costs that have been included in this case; the Company has not made cost updates to the projects included in Confidential workpaper WP-RTB-5.

e. See subpart d above. Additionally, since all of these projects have received all necessary approvals and signatures, all corresponding spending has been approved by the Company.

f. The concept approvals contained in Confidential workpaper WP-RTB-5 are for projects for the 2021 test year. There is no historical spending to report.

g. See subpart f above.

h. Providing all requested concept approvals for 2019 and 2020 would be unduly burdensome and involve voluminous data and documentation. All such concept approval documents have received all necessary approvals and signatures within the Company.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
June 4, 2020

EXHIBIT AG-1.22

**CONFIDENTIAL ** EXHIBIT SUBSTITUTE

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Question:

32. Refer to page 63, lines 14-21, of Mr. Hugo's direct testimony. Please:
a. Confirm that the Company has obtained all environmental permits for the Dry Ash Cell Landfill construction project. If not confirming, please provide the dates when the permit requests will be submitted and the permits are expected to be received.
b. Provide the basis for the cost estimate and related cost components.
c. Has the Company received bids from multiple contractors and selected a winning bid yet? If yes, provide a copy of the winning bid and the number of bids received.

Response:

a. Confirmed. The Company has an existing construction permit and is able to construct Cell 6 under that permit. We are preparing a new construction permit to submit to EGLE by the end of August 2020. EGLE has 30 days to determine the permit is administratively complete, and then 120 days to review and approve the permit. The purpose of the revised construction permit is to regain airspace lost due to permit improvements to align with the new RCRA rules which required additional separation from the upper most groundwater aquifer. The construction permit application is not expected to defer the start of the cell 6 construction.

b. The projected cost of constructing Cell 6 was based on the cost of constructing Cell 5. The cells are next to each other, similar in size and similar in construction methods.

c. No, the Company has not bid the work out yet. The Company expects to have the Cell 6 construction documents completed by the end this year for bidding late this year/early next year as well as construction next year. Bids will be received late first quarter/early 2nd quarter in 2021 – estimated construction costs are based on Cell 5 work completed in 2018. The Company will be bidding out to a minimum of 3 qualified firms to complete this work.

Scott A Hugo

Scott A. Hugo
June 10, 2020

U20697-AG-CE-1189
Page **1** of **1**

Question:

33. Refer to page 66 of Mr. Hugo's direct testimony. Please:
a. Why are decommissioning costs being included in 2021 when the units will continue to operate and not be retired until May 2023?
b. Provide the source and basis for the cost estimate and a breakdown of costs.
c. If contractors will be performing all or some of the work, please identify the approximate percentage.
d. Has the Company already bid out the work to contractors? How many RFPs were issued and how many bids received?
e. What is the source of the $29 million and provide the amount planned to be spent by year?
f. Provide the cost for each item listed on lines 16 to 26.
g. Why are the Demineralized Water System Installation and the items on lines 19 through 22, and on line 26 being included in a decommissioning project?

Response:

a. As discussed in my direct testimony, in order to retire Karn Units 1 and 2 in May 2023, various utilities/systems which support the operation of Karn Units 1 and 2 as well as Karn Units 3 and 4 will have to be separated and/or new systems will have to be installed. This work is required in order to continue operation of Karn Units 3 and 4 beyond the retirement of Karn Units 1 and 2. These capital expenditures are required to comply with the Company's MPSC-approved IRP.
b. Please see Attachment U20697-AG-CE-1189_ATT_1 for a copy of the Karn Station utility study. The $29 million cost estimate is the mid-point of the low and high cost estimates reflected in the report.
c. The Company's current strategy is to award 100% of the work to contractors.
d. The Company has not yet bid out the work. The Company is currently planning to begin Contractor qualification and the bidding process(s) within 4th quarter 2020 through 2021.
e. See response to subpart (b) and see below:

Work ID	WorkItemName (Custom SQl	2020	2021	2022	2023
9929	**Karn 1&2 Decommissioning**	**$ 889,766**	**$ 10,295,862**	**$ 15,675,064**	**$ 1,789,545**

f. See Attachment U20697-AG-CE-1189_ATT_1 for the requested information.
g. See response to subpart (a) and Attachment U20697-AG-CE-1189_ATT_1.

Scott A. Hugo
June 10, 2020

EXHIBIT AG-1.25

****CONFIDENTIAL ****
EXHIBIT
SUBSTITUTE

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