STATE OF MICHIGAN
DEPARTMENT OF ATTORNEY GENERAL

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LANSING, MICHIGAN 48909

DANA NESSEL
ATTORNEY GENERAL

June 22, 2021

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

Dear Ms. Felice:

Re: MPSC Case No. U-20963

Enclosed for filing is the ***Direct Testimony and Exhibits of Sebastian Coppola,*** which are being filed on behalf of Attorney General Dana Nessel and related Proof of Service. I have also included the Attorney General's Comprehensive Exhibit List with this filing.

Sincerely,

Celeste Gill
Digitally signed by Celeste Gill
Date: 2021.06.22 14:25:42 -04'00'

Celeste R. Gill
Assistant Attorney General
Gillc1@michigan.gov
517-241-0298

cc: All Parties

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-20963

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	)

Direct Testimony

And Exhibits

of

Sebastian Coppola

On behalf of

Attorney General Dana Nessel

June 22, 2021

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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 DTE Gas Company (DTE Gas) 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.

- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in (CECo 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in 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.

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-20963. 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. Adjustments to Depreciation Expense
3. The Company's cost of capital
4. The level of operations and maintenance expenses
5. The Company's proposed service restoration cost deferral and recovery mechanism

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 – Adjusted Capital Contingency costs

2. Exhibit AG-1.2 DR Response – Distribution Capital Ex 2015-2022 & 2020 Actual
3. Exhibit AG-1.3 DR Response – Center Suspended Streetlights Cost and Units
4. Exhibit AG-1.4 DR Response – Streetlight Outage Restoration Tracker App
5. Exhibit AG-1.5 DR Response – LVD Asset Relocation Costs 2017-2021
6. Exhibit AG-1.6 DR Response – Grid Modernization Costs 2017-2021
7. Exhibit AG-1.7 DR Response – LVD Substation Reliability Costs 2020 and 2021
8. Exhibit AG-1.8 DR Response – System Control Projects 2021
9. Exhibit AG-1.9 DR Response - Power Generation Projects Not Approved
10. Exhibit AG-1.10 DR Response –Hydro Units No Cost/Benefit Analysis
11. Exhibit AG-1.11 DR Response – Excess Overhead Allocation
12. Exhibit AG-1.12 DR Response – Actual 2020 Capital Expenditures
13. Exhibit AG-1.13 DR Response – Customer Service Centers Timeline & Occupancy
14. Exhibit AG-1.14 DR Response – Marshall Training Center
15. Exhibit AG-1.15 DR Response – UCC Project
16. Exhibit AG-1.16 DR Response – Return to Work Project.
17. Exhibit AG-1.17 DR Response – Facilities 2020 Actual Capital Expenditures
18. Exhibit AG-1.18 Transportation Equipment Capital Expenditures 2020-2011 WP
19. Exhibit AG-1.19 DR Response – Workforce Expansion Transportation Equip.
20. Exhibit AG-1.20 DR Response – Telematics Selection and Cost Savings
21. Exhibit AG-1.21 DR Response – Telematics Installation & Benefits Status
22. Exhibit AG-1.22 DR Response – CRM IT Project
23. Exhibit AG-1.23 DR Response – C&I Account Management System IT Project
24. Exhibit AG-1.24 DR Response – Bill Design & Delivery IT Project
25. Exhibit AG-1.25 DR Response – Customer Self-Service Mobile App IT Project
26. Exhibit AG-1.26 DR Response – Customer Loyalty & Alternative Payment Pilot
27. Exhibit AG-1.27 DR Response – IT Devices Replacement
28. Exhibit AG-1.28 DR Response – Digital-Hybrid Cloud and Data Center Transform
29. Exhibit AG-1.29 DR Response – Core HR IT Project
30. Exhibit AG-1.30 DR Response – Integrated Business Planning and Reporting
31. Exhibit AG-1.31 DR Response – IT 2020 Actual Capital Expenditures

32. Exhibit AG-1.32 Summary Cap Ex, Rate Base and Depreciation Expense
33. Exhibit AG-1.33 Overall Cost of Capital
34. Exhibit AG-1.34 Cost of Common Equity
35. Exhibit AG-1.35 Cost of Common Equity-DCF
36. Exhibit AG-1.36 Cost of Common Equity-CAPM
37. Exhibit AG-1.37 Cost of Common Equity-Risk Premium
38. Exhibit AG-1.38 Market to Book Ratios
39. Exhibit AG-1.39 ROE Decisions by Regulatory Commissions
40. Exhibit AG-1.40 Peer Group Selection Screening
41. Exhibit AG-1.41 S&P and Moodys Credit Reports on CECo
42. Exhibit AG-1.42 Calculation of Impact of TCJA on Cash Coverage Ratios
43. Exhibit AG-1.43 DR Response – Equity Ratios of Utilities Unverified
44. Exhibit AG-1.44 DR Response – CMS Debt Rating Reports Refused
45. Exhibit AG-1.45 Values Line Report on Market Volatility vs. Risk
46. Exhibit AG-1.46 O&M Adjustments Summary
47. Exhibit AG-1.47 DR - Inflation Cost Adjustment Rerun with Staff Request
48. Exhibit AG-1.48 DR - Distribution O&M Expenses 2015 to 2022 & 2020 Actual
49. Exhibit AG-1.49 DR Response - Service Restoration Costs 2015-2020
50. Exhibit AG-1.50 DR Response – Storm Restoration Pre-Staging Staff & Cost
51. Exhibit AG-1.51 DR Response – Line Clearing Cost Increases
52. Exhibit AG-1.52 DR Response – Power Generation 2020 Actual O&M Expense
53. Exhibit AG-1.53 DR Response – Analytics & Outreach Staff 2019-2022
54. Exhibit AG-1.54 Uncollectible Accounts Expense
55. Exhibit AG-1.55 DR Response – Insurance Escalation Assumptions
56. Exhibit AG-1.56 Insurance Expense Test Year Calculation
57. Exhibit AG-1.57 DR Response – IT Investments Expense 2016-2018
58. Exhibit AG-1.58 DR Response – Cloud Computing Costs 2016-2022
59. Exhibit AG-1.59 DR Response – Incentive Comp Payouts and Operating Measures
60. Exhibit AG-1.60 DR Response – Other Employee Benefits
61. Exhibit AG-1.61 Pension and OPEB Plan Statement 2015-2022

62. Exhibit AG-1.62 Pension and OPEB Plans Expected Return Explanation
63. Exhibit AG-1.63 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 $225.1 million. The rate increase represents an overall increase in base rates of 5.5% and an increase of nearly 9% to residential base rates. It is noteworthy to point out that in the 2019 historical test year, the Company had a revenue sufficiency (excess over the required rate of return) of $25.1 million.[1] This is on top of the revenue sufficiency or excess of $21.8 million reported for 2018.[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]

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

[1] Exhibit A-1 (JRC-1), Schedule A-1.
[2] MPSC Case No. U-20697, Exhibit A-1 (HJM-1), Schedule A1.
[3] Exhibit A-1 (JRC-2), Schedule A2, page 4.

resulted in an extended period of excess earnings and returns on equity capital well above authorized levels.

Based on my 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 sufficiency or excess of $30.7 million.[4] This excess revenue finding should not be surprising giving the Company's earnings above the true cost of capital and the revenue sufficiency reported in the 2019 historical year. My conclusions and related adjustments are summarized below:

1. I recommend a reduction in capital expenditures of $731.5 million and a reduction of $487.9 million to rate base for the test year. This reduces the Company's revenue deficiency by $35.4 million.

2. I recommend that the Commission adopt a lower cost of capital rate of 5.42%, 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 $91.2 million.

3. I recommend a lower level of Operations and Maintenance expenses for the test year. This reduces the Company's revenue deficiency by $101.1 million.

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[4] This determination is based on my evaluation of the Company's filed positions and should not be interpreted as determination on 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 $30.5 million pertaining to the lower capital expenditures and additions to plant discussed above. This adjustment reduces revenue deficiency by $30.5 million.

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

6. I recommend that the Commission order the Company to present an analysis and evidence in the next rate and other future rate cases that the migration to Cloud Computing is resulting in net costs savings.

7. I recommend that the Commission order the Company to present in the next rate case a thorough analysis and justification of the decline in the Expected Return rates for both the pension and OPEB plans.

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, $121 million, or 54%, of the requested rate increase of $225 million is for a higher rate base related to new capital expenditures. The additional $76 million of the rate increase for operations and maintenance (O&M) expense, or 34% of the rate increase, is mostly related to the increase in capital expenditures and rate base.[5] 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 $839.4 million for 2020, $1.2 billion for 2021, and an additional $1.4 billion for 2022. These increases are in addition to capital expenditures of $2.5 billion made during the prior three years from 2017 to 2019.[6]

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 recent historical 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.

To provide some allowance for future increases in costs, I have applied a 2% inflation escalator in forecasting future capital expenditures. This inflation rate represents the

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[5] Michael Torrey direct testimony at page 6.
[6] Exhibit A-12, Schedule B-5 in MPSC Case Nos. U-20963, U-20697, and U-20134.

average inflation rate for 2020 to 2022 forecasted by HIS Markit, a forecasting firm used by the Company.

A. Contingent Capital Expenditures

The Company has disclosed that it included contingency costs of $8,577,000 for 2021 and $18,689,000 for 2022 in its forecasted capital expenditures in the power generation area. Page 4 of Revised Exhibit A-12, Schedule B-5.2 shows this information.[7] The Company did not report any additional contingency costs from other operations.

The total amount of $27,266,000 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 potential costs that may not actually be incurred but have nonetheless been added to rate base.

[7] Exhibit AG-1.1 includes DR AG-CE-593. In response to Staff Audit Request 294, the Company stated that it would file a revised Exhibit A-12, Schedule B-5.2, page 4, with the correct amounts shown in DR AG-CE-593.

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 before 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, U-20322, and U-20697, 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 $27,266,000 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 $641.2 million for the Electric Distribution plant in 2019, and forecasted $581.2 million for 2020, $696.1 million for 2021, and $766.3 million for 2022. 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 will 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 CAPITAL EXPENDITURES INFORMATION PRESENTED IN MR. BLUMENSTOCK'S TESTIMONY AND RESPONSES TO DISCOVERY?

A. Yes. Although Mr. Blumenstock has filed 303 pages of testimony, plus several exhibits, on the Company's distribution system, the testimony and exhibits often lack a complete basis or justification of how the test year capital expenditures were determined. This gap of information is even more pronounced with regard to the bridge years of 2020 and 2021, where limited or no explanation, basis or justification is provided on how those forecasted expenditures were determined. This lack of valuable information is compounded by the Company's refusal to provide historical and projected work units and activities for the various capital expenditure categories addressed in his testimony and exhibits.

For example, in discovery request AG-CE-586, the Company was asked to provide the number of units, projects or activities that support the actual capital expenditures for each year from 2015 to 2020, and the forecasted amounts for 2020 to 2022. In response, the Company stated that the information could not be provided because units, projects and activities are generally enumerated at the investment category level instead of the sub-program level.[8] This answer is perplexing because in his testimony in this rate case, Mr. Blumenstock often identifies some work units for the projected test year and the related cost per unit for historical periods at the sub-programs level requested. I will also point out that in Case No. U-20697, the Company was able to provide both the historical and forecasted work units at the same sub-program level as requested in this case. My direct testimony in that rate case attests to that fact.

The restricted availability of information in this rate case makes it more difficult to assess the reasonableness of the Company's capital forecasts and limits the ability to calculate more precise revised forecasts for certain capital expenditures, as I will point out specifically later in my testimony. Still another factor that has made the analysis more difficult is the frequent realignment of costs in sub-programs. In both this rate case in Exhibit A-35 (RTB-2) and in the prior rate case in a similar schedule, the Company has shifted portions of certain sub-programs to other sub-programs. Two examples in this rate case are the shift of Lines and Substation Rehabilitation-HVD (line 18) from Lines and Substation Failures-HVD (line 36) and Substation Rehabilitation-LVD (line 19) from

[8] Exhibit AG-1.2 includes the Company's response to AG-CE-586 and Attachment 1.

Substations Failures-LVD (line 37). This frequent reshuffling of cost categories makes the comparative analysis between forecasted and historical costs extremely difficult.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend that the Commission direct the Company to maintain and report work units and other supporting project information that supports the historical and forecasted capital expenditures at the sub-program level. Additionally, I recommend that the Commission instruct the Company to minimize cost reclassifications and to present information on a historical comparative basis in the filed exhibits when reclassifications are necessary.

1. LVD Lines New Business

On line 1 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures of \$86,260,000 for the year 2020, \$93,113,000 for 2021 and \$98,546,000 for 2022 to build new LVD lines for residential and small commercial customers. Beginning on page 55 of his direct testimony Mr. Blumenstock discusses this program and links the number services connected each year to the number of housing permits issued. On page 59 of his testimony, Mr. Blumenstock shows the number of new services installed each year from 2015 to 2019 and the average cost of installation per service. As stated earlier, the Company was asked to provide the number of new services along with other work units also for 2020 and refused to provide this information. However, as shown in Exhibit AG-1, the Company provided the actual capital expenditures of \$91,709,000 incurred in this sub-program for 2020. This amount exceeds the five-year average amount of \$65,018,000.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE LVD LINES NEW BUSINESS SUB-PROGRAM?

A. The Company has forecasted that it will install 9,300 new service lines in 2021 and 9,560 lines in 2022. The forecasted numbers for 2021 and 2022 are increases of 277 units and 537 units over the 9,023 services installed in 2019. The Company has not provided any forecasted housing starts in its service territory for the two forecasted years to allow a determination that the forecasted new service lines for 2021 and 2022 are reasonably supported by increased housing and commercial activities in those years.

It would have been useful to have the number of new services installed in 2020, which were requested and not provided, to better assessed the trend from 2019 to 2021 and 2022. The number of new services for 2020 would have also permitted a better assessment of the cost per service given the significant escalation in unit costs from 2016 to 2019, which is shown on page 59 of Mr. Blumenstock's direct testimony. Figure 23 on this page of his testimony shows the installed cost per unit increasing by 43% from 2016 to 2017 and then increasing again in 2018 and 2019 by a cumulative 31% in those two years. For 2021 and 2022, the Company has forecasted an additional increase to \$10,012 and \$10,308 per service line, respectively.[9] This additional 12% increase in the cost per service in 2022 over the 2019 level is unsupported and excessive.

[9] For 2021: \$93,113,000 ÷ 9300 = \$10,012 per service. For 2022: \$98,546 ÷ 9560 = \$10,308 per service.

Based on the available information, the 2019 actual capital expenditures of $83,474,000 is the best supported amount reflecting 9,023 new services at a cost of $9,200 each as a base amount. To arrive at the forecasted capital expenditures for 2021 and 2022, I have applied a 2% average annual inflation factor. The result is forecasted capital expenditures of $86,846,000 for 2021 and $88,583,000 for 2022.[10] The Company's forecasted capital expenditures of $93,113,000 for 2021 and $98,546,000 for 2022 are not adequately supported or justified. Therefore, I recommend that the Commission remove $6,267,000 and $9,963,000 from the Company's forecasted capital expenditures for 2021 and 2022, respectively.

2. HVD Strategic Customers New Business

On line 3 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures of $6,036,000 for the year 2020, $17,281,000 for 2021 and $10,000,000 for 2022 to connect new large commercial and industrial customers. Beginning on page 60 of his direct testimony Mr. Blumenstock discusses this program and states that after the Company receives an inquiry for electric service, it may take months or years before a contract is signed to allow the Company to proceed with construction. On page 63 of his testimony, Mr. Blumenstock states that its 2021 capital expenditure forecast for this sub-program reflects the forecast for 2021 approved by the Commission in Case No. U-20697. For 2022, the Company has forecasted a "ballpark" number of $10 million with Mr.

[10] For 2021: $83,474,000 x 1.02 x 1.02 = $86,846,000. For 2022: $86,846,000 x 1.02 = $88,583,000.

Blumenstock stating that although higher than the five-year average amount of $8.5 million, it is possible it can be achieved.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE HVD STRATEGIC CUSTOMERS NEW BUSINESS SUB-PROGRAM?

A. The Company forecasted capital expenditures for this sub-program for 2021 and 2022 lack sufficient support and are not adequately justified. Although the 2021 forecasted amount of $17,281,000 for this sub-program was not litigated and the Commission may have approved it as part of other capital expenditures, it does not mean that it is sacrosanct and should not be justified and revisited in this rate case. It is probable that some of the projects, assumptions, timing and cost components of the 2021 may have changed a year later. As such, those projects, assumptions, timing and cost components need to be disclosed and justified in this rate case. Unfortunately, the Company has not done so and has not provided any supporting data to justify the forecasted capital expenditures of $17,281,000.

Regarding the 2022 capital expenditures, the Company's forecast of $10 million is far above the five-year average of $8,450,000 and the increase is unsubstantiated. Due to the lack of supporting evidence, and the fact that the Company only spent $4,038,000 in 2020 in this sub-program, as shown on line 3 of the attachment to DR AG-CE-586 in Exhibit AG-1.2, the best forecast for 2021 and 2022 is to escalate the five-year average amount of

$8,459,000 by a 2% inflation factor. The result is a forecasted capital expenditures amount of $8,801,000 for 2021 and $8,977,000 for 2022.[11]

The Company's forecasted amounts of $17,281,000 for 2021 and $10 million for 2022 are not adequately supported or justified. Therefore, I recommend that the Commission removed the excess amount of $8,480,000 for 2021 and $1,023,000 for 2022 from the Company's forecasted capital expenditures.

3. LVD Lines Demand Failures

On line 35 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures of $106,079,000 for the year 2020, $82,540,000 for 2021 and $84,031,000 for 2022 to repair or replace LVD electric lines during routine failures or storm restoration. Beginning on page 79 of his direct testimony, Mr. Blumenstock discusses this program and identifies two major components to this sub-program: service restoration orders and streetlight failures.

On page 83 of Mr. Blumenstock's testimony, the Company has identified the $84 million of capital expenditures for 2022 to consist of $64,185,000 for service restoration orders and $19,846,000 pertaining to streetlight failures. In his testimony, Mr. Blumenstock states that the increase in spending in 2020 was due to a surge related to COVID-19

[11] For 2021: $8,459,000 x 1.02 x 1.02 = $8,801,000. For 2022: $8,801,000 x 1.02 = $8,977,000.

emergencies and the Company expects service restoration costs to return to historical normal levels in 2021 and 2022.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE LVD LINES DEMAND FAILURES SUB-PROGRAM?

A. With regard to the service restoration portion of this sub-program, the forecasted capital spending for 2021 and 2022 seems reasonable. However, the streetlight failures capital expenditures forecasts for 2021 and 2022 are excessive.

Company witness Gregory Griffin addresses the issue of failing streetlights in his direct testimony. On page 18 of his testimony, Mr. Griffin states that the Company is now converting High Intensity Discharge (HID) streetlights to Light Emitting Diode (LED) lights as the HID lights fail. In response to discovery, the Company reported that due to this effort to convert HID lights to LED, the number of HID lights repaired is declining, which lowers O&M expense, but capital expenditures are increasing due to conversion of more streetlights to LED. Exhibit AG-1.3 includes the discovery response showing these opposing trends with volumes and dollar amounts.

Although the discovery response shows the declining trend in O&M expense and increase in capital expenditures, the volumes and costs are not proportional. As shown in the attachment to DR AG-CE-968 in Exhibit AG-1.3, the decrease in the number of HID and other streetlights repaired from 2016 to 2020 is significant, showing a 67% decline.

However, O&M expense has not declined and in fact has increased slightly from $1,654,000 in 2016 to $1,680,000 in 2020.

On the other hand, capital expenditures have increased four-fold from $2.5 million in 2016 to $10.5 million in 2020 with a 230% increase in the number of streetlight conversion to LED. In 2019, the Company converted 14,590 streetlights to LED fixtures, and in 2020 it converted 13,599 streetlights. The average number for the two years is 14,100, rounded up. This is nearly double the number converted in 2018 and more than three times the number converted in 2016.

For 2021 and 2022, the Company forecasted 24,675 streetlight conversions to LED each year. The forecasted capital expenditures are $19,494,000 for 2021 and $19,846,000 for 2022.[12] The 75% increase in the number of streetlight failures to 24,675 in 2021 and 2022 from the 14,100 average in 2019 and 2020 is not supported and not realistic. The Company has stated that it is converting the HID lights to LED fixtures as the HID lights fail. There is no evidence that the number of failures will suddenly accelerate by 75% in one year.

Additionally, the Company's 2021 and 2022 capital expenditures forecast reflects a cost per unit of $790 and $804, respectively. These unit costs imply a further escalation over the $771 cost in 2020. The attachment to DR AG-CE-968 in Exhibit AG-1.3 shows that unit costs declined from $614 in 2016 to $465 in 2018 and then increased in 2019 and 2020. The Company needs to rein in the escalating unit cost in this sub-program. A

[12] CECo response to DR AG-CE-968 in Exhibit AG-1.03.

reasonable unit cost for 2021 and 2022 is the average of the past three years escalated for inflation. For the three years 2018 to 2019, the average unit cost was $605. Escalated for inflation for 2021 at 2%, the unit cost is $617, and for 2022, it is $629.

To arrive at a reasonable capital expenditure forecast for 2021, I have multiplied the $617 by the average number of units of 14,100 in 2019 and 2022. The result is a 2021 capital expenditure forecast of $8,700,000. Similarly, for 2022, the $629 unit cost multiplied by the 14,100 units results in a capital forecast of $8,869,000.

The Company's forecasted capital expenditures of $19,494,000 for 2021 and $19,846,000 for 2022 are unsupported and excessive. Therefore, I recommend that the Commission remove the excess amounts of $10,794,000 and $10,977,000 from the Company forecasted capital expenditures for 2021 and 2022, respectively.

Q. DO YOU HAVE OTHER CONCERNS WITH SOME OF THE PROPOSALS INCLUDED IN MR. GRIFFIN'S TESTIMONY ON THE STREETLIGHTS SUB-PROGRAM?

A. Yes. In his testimony, Mr. Griffin discusses three issues that raise concerns. First, the Company seeks to implement a new software system, the Streetlight Outage & Restoration Tracking Application (SOAR), at a cost in excess of $3.3 million to allow customers to report streetlight outages, to track the status of the unrepaired lights, and to dispatch a

Company employee to repair the streetlight.[13] It is not clear why a new system is needed to accomplish tasks that should already be part of the Company customer service order system. Repairing streetlights, like repairing or replacing electric meters or other facilities, is not a new task. The Company has not provided any evidence or convincing rationale why such an app is necessary and what significant benefits will be derived to justify the large capital expenditure required to develop and implement it. The focus ought to be on getting the reported broken streetlights repaired or converted to LED as quickly as possible so that customers have no need to download an App on their phones or computers to track the status of broken streetlights. The additional capital expenditures of $3.3 million are unnecessary and should be removed from the Company's 2021 forecasted capital expenditures.

Second, the Company is exploring the use of a pilot program to install advanced lighting controls on streetlights that would signal a failure and avoid having customers report a streetlight outage. The Company admits that having customers report streetlight outages is a very cost-effective method. The Company also acknowledges that having municipalities report outages on a more frequent basis would avoid large spikes in workload and repair backlogs.[14]

Although the installation of advance lighting controls seems enticing, such a project needs to be weighed against the cost of installation and maintenance and must be economically

[13] Exhibit AG-1.04 includes CECo's response to DR AG-CE-967.
[14] Id., see CECo's responses to AG-CE-965 and 966.

justified. A pilot program should only begin if the financial cost/benefit analysis of installing these devices shows that it would be a sound economic decision. The Commission should instruct the Company to perform a cost/benefit analysis before undertaking a pilot program for advanced lighting controls and to first implement more cost-effective procedures with municipalities to report streetlight outages on a more frequent basis.

Third, although I agree with the Company's strategy to convert HID streetlights and any remaining Mercury Vapor, High Pressure Sodium, and Metal halide streetlights to LED as these older streetlights fail, certain customers may wish to accelerate the conversion for their own self-interest, such as reducing energy usage. Customers that wish to accelerate streetlight conversions need to contribute toward the cost of conversion. I recommend that the Commission order the Company to set a reasonable charge for the contribution in aid of construction for any accelerated implementations.

4. LVD Asset Relocations

On line 44 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures of $35,685,000 for the year 2020, $48,945,000 for 2021, and $52,506,000 for 2022 to relocate LVD electric lines. Beginning on page 101 of his direct testimony, Mr. Blumenstock discusses this program and states that most asset relocation work is entirely unplanned and reactive to requests from third parties external to the Company.

In Figure 35 on page 106 of his testimony, Mr. Blumenstock has subdivided the $52.5 million of forecasted capital expenditures for 2022 into three categories: relocations due to third party requests, LVD under-build relocations, and make-ready work. In Exhibit A-35, line 44, the Company calculated the 5-year average spending level for this sub-program at $26.3 million. The Company's explanation for the doubling in capital expenditures in 2022 from the 5-year average is that it has seen a large increase in requests for relocations since 2018 and expects make-ready work to stay at elevated levels. The Company also states that more relocations may be required as it increases work on the HVD system and responds to customer-driven relocations which have increased at a 14% annual rate.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE LVD ASSET RELOCATIONS SUB-PROGRAM?

A. The Company's explanations for the doubling of capital expenditures in 2022 from the 5-year average amount, and in comparison to more recent years, are very general and unconvincing. As shown in Exhibit AG-1.2 for this same line number, the Company only spent approximately $33.0 million in 2020. In response to discovery, the Company provided a comparison of capital spending in each of the three categories discussed above. The comparison shows that in 2021 capital expenditures are forecasted to increase from 2020 in each of the three categories, with the largest increase of $8.8 million in make-ready work. The other two categories are increasing by a combined amount of approximately $5.0 million for a total increase of $13.8 million. However, no specific basis or analysis was presented by the Company to support the increase in any of the three categories from 2020 to 2021 and into 2022.[15]

Given the lack of supporting evidence to justify the large increase in capital expenditures in 2021 and 2022, and the fact that the work in this program is unplanned and generally unknown at the time the forecasts were developed, I have determined that the best approach is to develop a forecast for 2021 and 2022 based on the highest amount actually spent in the past five years, which occurred in 2020. The $32,961,000 spent in 2020 is the most recent actual amount spent and is approximately $7.0 million higher than the 5-year average calculated by the Company. I selected this approach in consideration of the Company's view that work in this sub-program has been increasing recently.

Using the 2020 actual expenditure amount and applying a 2% inflation factor, I calculated a forecasted capital expenditure amount of $33,620,000 for 2021. Similarly, using the 2021 forecast and applying also a 2% inflation factor, I calculated the 2022 capital expenditure forecast at $34,293,000.

I find the Company's forecasted amounts of $48,945,000 for 2021 and $52,506,000 excessive and not adequately supported. Therefore, I recommend that the Commission remove the excess amounts of $15,325,000 and $18,213,000 from the Company's forecasted capital expenditures for 2021 and 2022, respectively.

[15] Exhibit AG-1.5 includes DR ST-CE-099.

5. LVD Lines Reliability

On line 8 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures of $30,684,000 for the year 2020, $40,658,000 for 2021, and $45,862,000 for 2022 to replace or improve electric circuits, replace electric poles, and acquire land easements or land right of way rights. Beginning on page 119 of his direct testimony, Mr. Blumenstock discusses this sub-program and links the activities to the Company's goal to upgrade the LVD system. On page 126 of his testimony, Mr. Blumenstock shows the capital expenditures forecasted for 2022 by category with related work units. No comparative work units for prior years are shown in the testimony. As stated earlier, the Company was asked to provide the number of work units for historical years 2015 to 2020 and refused to provide this information. This lack of comparative information impairs the analysis and assessment of the reasonableness of the Company's forecasted capital expenditures for 2021 and 2022.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE LVD LINES RELIABILITY SUB-PROGRAM?

A. On page 126 of Mr. Blumenstock's testimony, the Company has forecasted that in 2022 it plans to improve 103 circuits at a cost of $26.5 million, replace 1,526 poles at a cost of $13.8 million, perform enhancements to 80 exit-circuits at a cost of $1.3 million and purchase easements and ROW at a cost of $4.2 million for a total amount of $45.9 million. No similar detail was provided for 2021 or historical prior years. Therefore, it is not possible to perform an effective analysis of the projected capital expenditures for 2021 and 2022. While the Company listed several locations on pages 1-5 of Exhibit A-48 where it plans to focus its attention in 2022, it is not clear why these locations were selected over other locations and why an escalation over the number of facilities and locations in 2019 and 2020 is warranted.

Of great concern also is the significant increase in the cost of performing improvements to electric circuits and pole replacements. On page 127 of his direct testimony, Mr. Blumenstock shows that the average cost to complete a circuit upgrade increased from $80,400 in 2017 to $206,000 in 2018. This is an increase of 156%. The cost increased further to $222,600 in 2019 and based on the Company's forecast for 2022 is projected to increase again to $257,272 per average circuit.[16] Mr. Blumenstock attributes the increase to increases in labor costs and the addition of a third member to the work crews in 2018. Although these may be contributing factors, the difference of $126,000 on an average circuit between 2017 to 2018 would pay for an employee for an entire year, not just for a single circuit.

Similarly, the cost to replace an electric pole jumped from $4,700 in 2017 to $7,300 in 2018, a 55% increase. The cost per pole increased further in 2019 to $8,200 and is

[16] Figure 37 on page 126 of Mr. Blumenstock direct testimony: $26,499,000 ÷ 103 units = $257,272.

projected to increase further in 2022 to $9,058.[17] Over a five-year period from 2017 to 2022, the cost per pole replacement has nearly doubled.

In response to discovery, the Company provide actual cost per circuit and for pole replacements for 2020 which are lower than 2019. However, for 2021, the Company has forecasted unit costs to go up to $229,100 per circuit improvement, and for pole replacements the cost per unit is forecasted to stay at the 2020 level of $7,900.[18] This continued escalation in unit costs, particularly in the circuit improvement category has not been substantiated and is not sustainable. The Company needs to take corrective action to not only stop the increase but to reverse the trend.

Based on the available information provided by the Company and to set an appropriate level of expenditures that will provide an incentive for the Company to control and reverse unit cost increases, I have determined that the 2021 and 2022 capital expenditures forecast should be set based on the higher amount of the five-year average or the most recent level of expenditures in 2020. The five-year average amount through 2019 is $36,839,000, while the Company spent $33,257,000 in 2020. Using the five-year average amount, as the higher of the two amounts, the 2021 forecast capital expenditures are $38,327,000 after applying the 2% inflation factor for two years. Similarly, for 2022, the forecasted capital expenditures are $39,094,000.[19]

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[17] *Id.*, $13,823,000 ÷ 1,526 poles = $9,058.
[18] CECo response to DR ST-CE-561.
[19] For 2021: $36,839,000 x 1.02 x 1.02 = $38,327,000. For 2022: $38,327,000 x 1.02 = $39,094,000.

The Company's forecasted capital expenditures of $40,658,000 for 2021 and $45,862,000 for 2022 are excessive, not adequately justified or supported. Therefore, I recommend that the Commission remove $2,330,000 and $6,768,000 from the Company's forecasted capital expenditures for 2021 and 2022, respectively.

Furthermore, I recommend that the Commission direct the Company to take all appropriate actions to prevent further escalation in the cost to upgrade electric circuits and pole replacements and implement more efficient processes to reverse the current trend of cost increases.

5. HVD Lines Reliability

On line 9 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures of $22,679,000 for the year 2020, $63,909,000 for 2021, and $78,439,000 for 2022 to rebuild HVD lines, rehabilitate pole-tops, pole replacements, and replace electric switches, including SCADA additions. Beginning on page 130 of his direct testimony, Mr. Blumenstock discusses this sub-program and the general approach used to identify worthy projects. On page 135 of his testimony, Mr. Blumenstock shows the capital expenditures forecasted for 2022 by category with related work units. Like the LVD Line Reliability sub-program discussed above, no comparative work units for prior years are provided in the testimony. As stated earlier, the Company was asked to provide the number of work units for historical years 2015 to 2020 and refused to provide this information. This is another case where the lack of comparative information impairs the analysis and assessment of the reasonableness of the Company's forecasted capital expenditures for 2021 and 2022.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE HVD LINES RELIABILITY SUB-PROGRAM?

A. On page 135 of Mr. Blumenstock's testimony, the Company has forecasted that in 2022 it plans to perform approximately 97 miles of HVD line rebuilds at a cost of $46.3 million, rehabilitate 132 miles of pole tops at a cost of $12.4 million, replace 880 poles at a cost of $18.6 million, and install 18 SCADA and other switches at a cost of $1.2 million, for a total amount of $78.4 million. No similar detail was provided for 2021 or the historical prior years. Therefore, it is not possible to perform an effective analysis of the projected capital expenditures for 2021 and 2022. Although the Company has listed several locations on pages 5-6 of Exhibit A-48 and in Exhibit A-52 where it plans to focus its attention in 2022, the listed locations appear to be a general target list from which it will pick the projects to work on as 2022 approaches. In other words, the Company did not know at the time it prepared its forecast for 2022 which specific projects made up the forecasted amount. This is simply a list of possibilities. Therefore, the actual spending level for 2022 could vary significantly for the forecasted amount. Pages 139 and 140 of Mr. Blumenstock's testimony make this point clear.

From the forecasted capital expenditures for 2021 and 2022, it is apparent that the Company wants a major escalation in activity in this sub-program. The Company is forecasting that it will spend $63.9 million in 2021 and $78.4 million in 2022 when on average in the past five years it has spent $32.1 million annually and in 2020, the most recent year of actual capital expenditures, it only spent $22.3 million. Nowhere in Mr. Blumenstock's testimony is there an explanation or justification why such a three-fold-plus increase in spending from $22.3 million in 2020 to $63.9 million in 2021 and $78.4 million in 2022 is required or advisable. Despite pages and pages of testimony, this analysis and justification are missing.

The large escalation in capital spending in this sub-program is excessive and not adequately justified. Based on the limited information provided by the Company, I have determined that the 2021 and 2022 capital expenditures forecast should be based on the higher amount of the five-year average spending or the most recent level of expenditures in 2020. The five-year average amount through 2019 is $32,063,000, while the Company spent $22,679,000 in 2020. Using the five-year average amount, as the higher of the two amounts, the 2021 forecast capital expenditures are $33,358,000 after applying the 2% inflation factor for two years. Similarly, for 2022, the forecasted capital expenditures are $34,026,000.[20]

Therefore, I recommend that the Commission remove $30,551,000 and $44,413,000 from the Company's forecasted capital expenditures for 2021 and 2022, respectively.[21]

[20] For 2021: $32,063,000 x 1.02 x 1.02 = $33,358,000. For 2022: $33,358,000 x 1.02 = $34,026,000.
[21] For 2021: $63,909,000 CECo forecast - $33,358,000 AG Forecast = $30,551,000. For 2022: $78,439,000 CECo forecast - $34,026,000 AG forecast = $44,413,000.

6. Grid Modernization

On line 15 and 16 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures for grid automation and modernization. Line 15 pertains to the installation of DSCADA controllers, ATR Loops, line sensors, regulator controllers, and capacitator upgrades and replacements. On this line, the Company shows forecasted capital expenditures of $44,457,000 for the year 2020, $56,832,000 for 2021, and $61,465,000 for 2022.

On line 16, the Company includes technology projects to further automate the grid system through the installation of software systems and grid management systems. On this line, the Company shows forecasted capital expenditures of $18,871,000 for the year 2020, $21,458,000 for 2021, and $21,906,000 for 2022.

The combined capital expenditures on the two lines for 2021 and 2022 are $71.2 million and $83.4 million, respectively. Beginning on page 153 of his direct testimony, Mr. Blumenstock discusses the Grid Modernization sub-programs and the several categories therein.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE GRID MODERNIZATION SUB-PROGRAMS?

A. I will discuss my assessment of the Company’s forecasted capital expenditures into two parts. First, I will discuss the more routine and repetitive program expenditures on line 15 of Exhibit A-35. Second, I will discuss the special projects to upgrade and install software and grid management systems reflected on line 16 of Exhibit A-35.

With regard to the first part, on page 168 of his testimony, Mr. Blumenstock shows the capital expenditures forecasted for 2022 by category with related work units in the first five lines of Figure 445 (45). The forecasted capital expenditures on these five lines total to $61,495,000, as shown on line 15 of Exhibit A-35. Like the LVD and HVD Line Reliability sub-programs discussed above, no comparative work units for prior years are shown in the testimony, and the Company refused to provide this information for historical years 2015 to 2020 in response to discovery.[22] This is another case where the lack of comparative information impairs the analysis and assessment of the reasonableness of the Company's large escalation in forecasted capital expenditures for 2021 and 2022.

The Company has not provided sufficient information to determine the appropriate context of dollars spent versus units completed in prior years so that a comparison can be made against forecasted periods. If the number of units of work forecasted for 2022 represent a significant increase over prior years, the extent of the increase is unknown. The overall increase in capital expenditures forecasted for 2021 and 2022 would indicate perhaps an increase in the number of units to be installed or could also reflect an increase in the unit cost. The Company has not provided sufficient information to perform that type of

[22] Exhibit AG-1.2.

analysis in order to permit an assessment of the reasonableness of the forecasted capital spending against historical benchmarks.

Nowhere in Mr. Blumenstock's testimony is there an explanation or justification of why grid automation capital expenditures are increasing three-fold in 2021 and 2022 from the five-year average amount, or for that matter in comparison to the more recent years of 2019 or 2020. The large increase in capital spending in this sub-program is excessive and not adequately justified.

Based on the limited information provided by the Company, I have determined that the 2021 and 2022 capital expenditures forecast should be set based on the higher amount of the five-year average spending or the most recent level of expenditures in 2020. The five-year average amount through 2019 is $21,742,000, while the Company spent $43,593,000 in 2020.[23] Using the 2020 actual capital expenditures, as the higher of the two amounts, the 2021 forecast capital expenditures are $44,465,000 after applying the 2% inflation factor. Similarly, for 2022, the forecasted capital expenditures are $45,354,000.[24]

The Company's forecasted capital expenditures for 2021 of $56,832,000 and $61,495,000 for 2022 are excessive and unsupported. Therefore, I recommend that the Commission remove $12,367,000 and $16,141,000 from the Company's forecasted capital expenditures for 2021 and 2022, respectively.

[23] *Id.*
[24] For 2021: $43,593,000 x 1.02 = $44,465,000. For 2022: $44,465,000 x 1.02 = $45,354,000.

Q. PLEASE PROVIDE YOUR ASSESSMENT AND RECOMMENDATION FOR THE SECOND PART OF THE GRID MODERNIZATION SUB-PROGRAMS.

A. As shown in Figure 45 on page 168 of Mr. Blumenstock's testimony, the Company has included eight new systems, or upgrades to existing systems, in its forecasted capital expenditures for 2022. The total amount of these eight items is $21.9 million. Some of these systems have capital expenditures spanning multiple years. For example, in response to discovery request ST-CE-109, the Company disclosed that it also plans to spend $1.2 million on the DERMS system, $3.5 million on the Reliability Predictive Analytics system and $2.5 million on the Grid Modernization Incubator in 2021.[25] It is likely that some of these systems also have capital expenditures past 2022. In other words, the full scope of the capital expenditures for each of these systems has not been disclosed by the Company and is unknown. The limited disclosure on the full scope of each project's total cost is concerning because it could result in the Commission approving the capital expenditures shown in a given year when the full cost of the project could be many times more when considering the cost of the project from inception to completion.

A case in point is the ADAMS system expansion. The Commission approved some capital expenditures for this system in previous rate cases. The Company now discloses that it expects to do a major upgrade of the system in 2022 at a cost of $7.4 million. This information was not disclosed in prior rate cases when the Company requested approval

[25] Exhibit AG-1.06 includes DR ST-CE-109.

of the capital spending for the initial system implementation in 2019. The necessity of the system upgrade less than two years after it was implemented is not clear. The three "enhancements" discussed beginning on page 158 of Mr. Blumenstock's testimony do not seem to be critical items and in some cases should have been part of the base software system. No quantifiable benefits have been presented by the Company to justify the $7.4 million in spending on this item in 2022 and perhaps even more in future years. The Commission should reject the $7,400,000 of capital expenditures proposed for 2022, as not adequately supported and justified.

Regarding the DERMS system, on page 160 of his testimony, Mr. Blumenstock states that in Case No. U-20697, the Commission rejected the Company's proposed spending for 2021 for this system because the Company had not made a convincing case that it would be beneficial. Unfortunately, in this case the Company again failed to make a compelling and convincing case that the Commission should approve the $2.4 million of capital expenditures for this system forecasted for 2021 and 2022, with potentially even more spending past 2022. Mr. Blumenstock's testimony fails to provide sufficient evidence that without DERMS the power grid cannot operate efficiently. The statements offered by Mr. Blumenstock are very general and do not provide sufficient justification for the Commission to approve the proposed capital expenditure. I recommend that Commission disallow the $1,188,000 of forecasted capital expenditures for 2021 and the $1,191,000 for 2022. The capital expenditures have not been sufficiently supported and justified.

The next large capital expenditure is for the Reliability Predictive Analytics system. The Company has forecasted $1.2 million for 2022 in Figure 45 and an additional $3.5 million for 2021, as discussed above. It is not known if there are additional capital expenditures after 2022, which could further add to the known cost of $4.7 million identified so far. On pages 162 and 163 of his testimony, Mr. Blumenstock explains the features and potential benefits that this system could yield.

However, as desirable as it may be to have more photographs of the Company's facilities integrated into the Company's GIS, the cost of this system must be justified by quantifiable benefits that exceed the capital spending. The Company has not presented any evidence that an advantageous cost/benefit analysis has been prepared to economically justify undertaking this project. I recommend that the Commission disallow $3,550,000 of capital expenditures for 2021 and $1,200,000 for 2022.

Another large project identified in Figure 35 and discussed by Mr. Blumenstock beginning on page 164 of his testimony, is the Grid Modernization Incubator. Figure 35 identifies $8.4 million of capital expenditures for 2022 and the Company's discovery response in Exhibit AG-1.6 shows an additional $2.5 million for 2021. This project would cost at least $10.9 million for the two years and potentially more in future years for amounts not yet disclosed.

From Mr. Blumenstock's testimony, it appears that what the Company is proposing is a testing and training facility to try different new technologies and experiment with new electrical equipment. This project sounds very similar to the Circuit 501 project that the Company proposed in Case No. U-20697 and the Commission rejected.[26] The proposed incubator or training facility has not been adequately scoped or defined, and it is unknown what the total cost of the facility will be. Furthermore, no related quantifiable benefits have been identified that would justify the capital investment. I recommend that the Commission remove the $2,522,000 of capital expenditures from 2021 and the $8,424,000 from 2022.

Lastly, the Company proposes approximately $3.0 million in capital spending between 2021 and 2022 for the Electric Distribution Asset Management project. Mr. Blumenstock dedicated a paragraph to this project on page 167 of his testimony. The essence of the Company proposal is that it wants to develop a Distribution Asset Management strategy with processes and technology. The testimony outlines several objectives and desired general outcomes but is very short on details. There is no identification what the $3.0 million would be spent on and why the investment is justified with hard cost savings or other quantifiable benefits. It is also not clear why developing a management strategy is a capital investment. Typically, development of strategy is a management planning function. This project has not been well defined or justified, and the proposed capital spending should be rejected by the Commission. I recommend that the Commission

[26] MPSC Case U-20697, order dated 12/17/2020 at page 101.

remove $992,000 from 2021 and $1,984,000 from the 2022 forecasted capital expenditures.

In summary, for the five projects discussed above, I recommend that the Commission disallow $8,252,000 and $20,199,000 from the Company's forecasted capital expenditures for 2021 and 2022, respectively.

7. Metro Reliability

On line 14 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures of $3,250,000 for the year 2020, $5,647,000 for 2021, and $5,575,000 for 2022 to replace or improve electrical facilities in metropolitan areas it serves. Mr. Blumenstock discusses this sub-program beginning on page 182 of his direct testimony. On page 185 of his testimony, Mr. Blumenstock shows the capital expenditures forecasted for 2022 by category with related work units. No comparative expenditures by category with work units for prior years are shown in the testimony. As stated earlier, the Company was asked to provide the number of work units for historical years 2015 to 2020 and refused to provide this information. This lack of comparative information impairs the analysis and assessment of the reasonableness of the Company's forecasted capital expenditures for 2021 and 2022.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE METRO RELIABILITY SUB-PROGRAM?

A. The Company spent approximately $2.4 million annually on average over the 5 years ended in 2019. Although in his testimony Mr. Blumenstock states that expenditures were down in 2017 and 2018 because there were fewer metro reliability needs, the actual capital expenditures in 2020 were only $3,516,000, or approximately $1.1 million higher than the average amount. However, for 2021, the Company forecasted capital expenditures of $5,647,000, which is 61% above the 2020 capital spending and more than double the five-year average. More concerning is the fact that the Company has provided no support for the projected capital expenditures for 2021 either by category, list of projects or units to be installed.

For 2022, the category breakdown and units listed in Figure 489 (49) on page 185 become meaningless given that there is no comparative information to prior years and no explanation why capital expenditures for 2021 and 2022 need to increase by more than 60% above 2020 level and more than double from the five-year average amount. The list of projects on page 8 of Exhibit A-48 is a repeat of the information in Figure 49 with some target locations. There is no explanation what specific work will be done at these locations, why it is necessary, and why it is priority work to be done in 2022. Furthermore, on page 186 of his testimony (line 3), Mr. Blumenstock states that a portion of the 2022 capital expenditures will go toward purchasing two “mobile vaults.” However, both figure 49 and Exhibit A-48 list only one “mobile vault”.

Based on the limited information provided by the Company, I have determined that the 2021 and 2022 capital expenditures forecast should be set based on the higher amount of the five-year average spending or the most recent level of expenditures in 2020. The five-year average amount through 2019 is $2,382,000, while the Company spent $3,516,000 in 2020. Using the 2020 expenditures, as the higher of the two amounts, I have calculated the 2021 forecasted capital expenditures at $3,586,000 after applying the 2% inflation factor. Similarly, for 2022, the forecasted capital expenditures are $3,658,000.[27]

The Company's forecasted capital expenditures of $5,647,000 for 2021 and $5,575,000 for 2022 are excessive and not adequately justified. Therefore, I recommend that the Commission remove $2,061,000 and $1,917,000 from the Company's forecasted capital expenditures for 2021 and 2022, respectively.

8. HVD Lines and Substations Rehabilitation

On line 18 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures of $13,967,000 for the year 2020, $38,521,000 for 2021, and $40,974,000 for 2022 to replace or improve HVD electrical lines and substation equipment where a failure has not yet occurred, but the Company believes it is imminent. Mr. Blumenstock discusses this sub-program beginning on page 186 of his direct testimony. In Figure 491 (51) on page 191 of his testimony, Mr. Blumenstock shows the capital expenditures forecasted for 2022 by category with related work units. In Figure 502 (52) on page 193 of his testimony, he provides historical spending by category for 2017 to 2020, albeit without work units, to

[27] For 2021: $3,516,000 x 1.02 = $3,586,000. For 2022: $3,586,000 x 1.02 = $3,658,000.

provide an historical perspective on the 2022 forecasted expenditures. No similar information was presented for the 2021 forecast.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE HVD LINES AND STATION REHAB SUB-PROGRAM?

A. This sub-program is a reclassification of costs previously included with HVD Lines and Substation Failures on line 36 of Exhibit A-35. Based on the comparative information provided in Figures 491 and 492, I find the forecasted 2022 capital expenditures for the first four categories to be reasonable. The fifth category, HVD Substation Replacement projects, has been forecasted to increase to $30.7 million for 2022, or $24 million from the actual amount of $6.7 million spent in 2020. On page 194 of his testimony and on page 14 of Exhibit A-48, Mr. Blumenstock identifies specific substations to be replaced or upgraded. These projects total to $25.7 million, or $5 million less than the $30.7 million forecasted for this work category.

After reviewing page 14 of Exhibit A-48, it is apparent that the remaining $5 million represents station rehab projects not yet identified but that could emerge subsequent to inspections. Line 55 on page 14 of Exhibit A-8 shows the amount of $4,685,000 pertaining to such unknown or emergent projects.

Costs for emergent projects are not much different than contingency costs. In this case, the Company has included a placeholder amount for projects not yet known. In prior rate cases, the Commission has rejected both contingency costs and placeholder amounts.

Therefore, I recommend that the Commission remove the $4,685,000 from the Company's forecasted 2022 capital expenditures.

With regard to the forecasted capital expenditures for 2021, the Company has not provided any details or supporting information by category or work units. Mr. Blumenstock's direct testimony is devoid of any discussion or explanation about the 2021 forecasted amount of $35.8 million and the increase in capital expenditures of $23 million from the $15.5 million spent in 2020. Due to the lack of supporting data and justification for the $23 million increase, I recommend that the Commission disallow this amount from the Company's forecasted capital expenditures for 2021.

8. LVD Substations Rehabilitation

On line 19 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures of $8,900,000 for the year 2020, $14,500,000 for 2021, and $13,500,000 for 2022 to replace or improve LVD substation equipment where a failure has not yet occurred, but the Company believes it is imminent. Mr. Blumenstock discusses this sub-program beginning on page 195 of his direct testimony. In Figure 524 (54) on page 201 of his testimony, Mr. Blumenstock shows the capital expenditures forecasted for 2022 by category with related work units. In response to discovery request ST-CE-691, the Company provided similar information for 2020 and 2021 but with no work units.[28] Most of the capital expenditures in 2020 through 2022 are for replacement of potentially failing transformers.

[28] Exhibit AG-1.7 includes DR ST-CE-691.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE LVD STATION REHAB SUB-PROGRAM?

A. On page 201 of his testimony, Mr. Blumenstock states that this a new sub-program started in 2020 and no historical actual spending for prior years is available. However, on page 199, he identifies the number of transformers replaced each year since 2017. This contradiction is perplexing. In 2020, the Company replaced six transformers at a cost of approximately $6.5 million. For 2022, the Company wants to more than triple the number of transformers to be replaced to 20 for a cost of $13.1 million with no explanation or justification why such a large increase is warranted. For 2021, the forecast for transformer replacement is $11.8 million without a specified number of units to be replaced.[29]

The forecasted capital expenditures by the Company for 2021 and 2022 are not adequately justified and are excessive based on recent actual expenditures in 2020. Using the 2020 actual expenditures of $9,838,000 for 2020 as a base amount and applying a 2% inflation factor, I calculated a 2021 forecast amount of $10,035,000 and a 2022 forecast of $10,235,000. The difference between these amounts and the Company's forecasts are $4,465,000 for 2021 and $3,265,000 for 2022. I recommend that the Commission remove those amounts from the Company's forecasted capital expenditures.

[29] *Id.*

9. LVD Lines Rehabilitation

On line 20 of Exhibit A-35 (RTB-2), the Company forecasted capital expenditures of $21,397,000 for the year 2020, $36,183,000 for 2021, and $53,666,000 for 2022 to replace or improve LVD electrical lines and substation equipment where failure has not yet occurred, but the Company believes it is imminent. Mr. Blumenstock discusses this sub-program beginning on page 203 of his direct testimony. As Mr. Blumenstock states in his testimony, this sub-program is another reclassification of work that was previously reported under the Demand Failure sub-program. Similar to other reclassifications and the general lack of historical comparative spending and number of units completed, these factors hinder the assessment of the forecasted spending for 2021 and 2022.

In Figure 546 (56) on page 207 of his testimony, Mr. Blumenstock shows the capital expenditures forecasted for 2022 by category with related work units. In Figure 557 (57) on page 208 of his testimony, he provides historical spending for only the Imminent Rehabilitation category for 2017 through 2019, albeit without work units. No similar information was provided for the Securities Assessment Repairs category, and as stated earlier, no comparative information for units or by category was provided for 2020 actual activity.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE LVD LINES REHAB SUB-PROGRAM?

A. The Company has forecasted that 2021 capital expenditures in this sub-program will increase by 33% over the average spending in 2018 and 2019, and also increase by 62% over the actual amount spent in 2020. The increased spending of $53,666,000 proposed for 2022 represents nearly a doubling of the average expenditures in 2018 and 2019, and a 140% increase over the actual amount spent in 2020. Other than general statements about the need to address deteriorating infrastructure, Mr. Blumenstock testimony is devoid of any specific explanation and justification why capital spending in 2021 and 2022 must double from recent actual spending levels.

The list of locations and projects on pages 15 to 21 of Exhibit A-48 and in Exhibit A-51 appear to be lists of potential locations that may or may not be rehabilitated pending further inspection. Mr. Blumenstock explains this approach on page 205 of his testimony. The combined lists of potential projects in Exhibit A-48 and A-51 total to 1,130 projects that the Company supposedly believes it can complete in 2022. There are no comparative units or project numbers provided for prior years that would allow an assessment of whether the 2022 plan is achievable.

It is also important to realize that the Company has renamed this sub-program to LVD Lines Rehabilitation from Demand Failures and "emergent rehabilitation." The previous category more accurately described the emergent or contingent nature of the rehabilitation required for these sections of the LVD electrical system. In other words, the Company did not know at the time that developed its forecast for 2022 specifically which projects and locations it would need to complete until further inspection of those lines is performed.

Adding to my skepticism of the Company's ability to achieve the level of expenditures forecasted for 2021 and 2022 is the significant increase in unit cost for the two categories of work to be performed. Figure 568 (58) on page 208 of Mr. Blumenstock's testimony shows the unit cost for completed work for Security Assessment Repairs and Imminent Rehabilitation. For the first category, during the five years ended 2019, the average unit cost was \$13,667 and ranged from \$9,600 to \$13,900 during this period. For 2022, the Company is now forecasting a unit cost for Security Assessment Repairs of \$125,227.[30] The increase in the unit cost from \$13,667 to \$125,227 is almost inconceivable.

Similarly, for the Imminent Rehabilitation category, the average unit cost for the five years ended 2019 was \$7,733 and ranged from \$4,300 to \$10,000 during the period. For 2022, the Company is forecasting a doubling of the unit cost to \$14,736 from the average level of \$7,733. No explanation or justification has been provided by the Company why such large increases in unit costs are reasonable and should be accepted.

Based on the limited information and lack of sufficient justification for the proposed capital expenditures, plus the emergent or contingent nature of the work to be performed in this sub-program, I have determined that a reasonable forecast for the years 2021 and 2022 should be based on the actual amount spent over the most recent three years from 2018 and 2020. The average amount spent by the Company over the three-year period is

[30] Page 207 of Richard Blumenstock direct testimony, Figure 546: \$41,951,000 ÷ 335 units = \$125,227 per unit.

$25,561,000.[31] To arrive at the forecasted amount of $26,594,000 for 2021, I escalated the three-year average amount by 2% for two years. For 2022, I increased the 2021 amount by an additional 2% to arrive at a forecasted amount of $27,125,000.[32]

The Company's forecasted capital expenditures for 2021 and 2022 are not adequately supported and justified. Therefore, I recommend that the Commission adopt the forecasted amounts I have developed based on historical expenditures and remove the excess amount of $9,589,000 for 2021 and $26,541,000 for 2022 from the Company's forecasts.[33]

10. Tools

On line 49 of Exhibit A-35, the Company forecasted capital expenditures of $5,507,000 for the year 2020, $8,872,000 for 2021, and $8,955,000 for 2022 to purchase new tools for employees and their trucks. Mr. Blumenstock discusses this capital expenditure category beginning on page 249 of his direct testimony. In Figure 625 (65) on page 250 of his testimony, Mr. Blumenstock subdivides the 2022 capital spending into two categories and provides the number of truck tool packages forecasted to be purchased. No comparable information was provided for prior years, and no explanation or justification for the 2021 proposed level of expenditures.

[31] Exhibit AG-1.2, AG-CE-586 Attachment, line 20: $31,949,000 + $22,403,000 + $22,331,000 = $76,683,00 ÷ 3 = $25,561,000.
[32] For 2021: $25,561,000 x 1.02 x 1.02 = $26,594,000. For 2022: $26,594,000 x 1.02 = $27,125,000.
[33] For 2021: $26,594,000 - $36,183,000 = $9,589,000. For 2022: $27,125,000 - $53,666,000 = $26,541,000.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE TOOLS PROGRAM?

A. In his testimony for this program, Mr. Blumenstock generally refers to the need to add more tools and vehicle tool packages to support the Company increased activities to rebuild, replace and upgrade the electrical infrastructure. The proposed 143 truck tool packages for 2022 have not been tied to any specific sub-programs and the Company did not disclosed how that number was determined. Even less informative is the forecast for 2021 where the Company has provided only a forecasted capital expenditure amount like 2022 with no supporting units or other details.

In his testimony, Mr. Blumenstock states that the Company has been purchasing truck tool packages since 2016.[34] Therefore, it is reasonable to expect that the five-year historical spending would reflect an increasing trend of spending for this program and the average for the five-years would reflect that increasing trend of spending. For the 5-year period ended 2019, the Company spent $3,073,000 on average annually on this program. In 2020, the Company only spent $3,611,000 after forecasting it would spend $5,507,000.[35]

From this historical record, it is apparent that the forecasted amount for 2021 of $8,872,000 and $8,955,000 for 2022 are significantly higher and inconsistent with historical levels. Mr. Blumenstock's testimony on this program presents no evidence to justify the proposed

[34] Mr. Blumenstock direct testimony at pages 249 and 251.
[35] Exhibit AG-1.2.

increases in spending. As a result of the limited information provided by the Company, I have determined that a reasonable forecast for 2021 and 2022 should be based on the highest of the 5-year average or the most recent actual level of spending in 2020. The actual spending of $3,611,000 in 2020 is higher than the 5-year average. Using this amount and escalating it by 2% results in a forecast of $3,683,000 for 2021 and $3,757,000 for 2022.

The Company's forecasted amounts of $8,872,000 for 2021 and $8,955,000 are excessive and unsupported. Therefore, I recommend that the Commission remove the excess amount of $5,189,000 and $5,198,000 for 2021 from the Company's forecast capital expenditures for 2021 and 2022, respectively.

11. System Control Projects

On line 50 of Exhibit A-35, the Company forecasted capital expenditures of $2,157,000 for the year 2020, $6,699,000 for 2021, and $4,944,000 for 2022 to improve management of the distribution system by improving the operation of the control centers, streamlining operations, and improving remote control capabilities. Mr. Blumenstock discusses this sub-program beginning on page 253 of his direct testimony. In Figure 647 (67) on page 255 of his testimony, Mr. Blumenstock subdivides the $4.9 million of forecasted capital expenditures for 2022 into three categories with the largest being HVD Operations Projects at $2.5 million. Most of the remaining amount is for Operations Center Modifications at

$1.9 million and the rest is for Operating Technology Enhancements for $569,000. No comparative information was provided for historical periods at this level of detail.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE SYSTEM CONTROL PROJECT SUB-PROGRAM?

A. As shown on line 50 of both Exhibit A-35 and Exhibit AG-1.2, the Company's annual average spending level during the five years ended 2019 was $807,000, and the Company spent near to the same amount in 2020 at $976,000 although forecasting that it would spend $2,157,000, or more than twice as much. Mr. Blumenstock's testimony is devoid of any specific explanation or justification why in 2021 and 2022 it needs to spend more than five to six times more than it spent in 2020 or on average in the prior five years.

The list of detailed projects for 2022 on page 43 of Exhibit A-48 to a large degree mirrors the summary information in Figure 647. The list of 132 planned sensor installation total to $1.2 million and it is not clear if these are definitive locations where sensors will be installed or simply a general target list from which the Company will pick projects for 2022. More importantly, the rest of the listed expenditures, such as $1.4 million for Operations Center Video Walls, have not been explained or justified.

In response to discovery, the Company provided a similar list of projects for 2021 and identified an additional $1.7 million to be spent on Operation Center Video Walls, $1.1 million for Control Room modifications, and $0.9 million to enhance storm restoration resource management tools.[36] Mr. Blumenstock's testimony is again devoid of any explanation or justification why these capital expenditures are necessary. In explaining the basis for the 2022 forecasted capital expenditures, on lines 13-19 of page 256 of his testimony, Mr. Blumenstock states that newfound opportunities, such as expanding SCADA to MOABS have driven new spending in 2018 and 2019 and continues to drive additional spending into future years as it identifies new opportunities. Although these appear to be worthy goals, there are no significant expenditures associated to them in 2021 and 2022 with quantifiable benefits. Page 43 of Exhibit A-48 and Exhibit AG-1.8 identify only $131,000 for 2021 and 2022 related to SCADA out of $6.7 million and $4.9 million forecasted in those years.

As a result of the limited information provided by the Company, I have determined that a reasonable forecast for 2021 and 2022 should be based on the highest of the 5-year average amount or the most recent actual level of spending in 2020. The actual spending of $976,000 in 2020 is higher than the 5-year average. Using this amount and escalating it by 2% results in a forecast of $996,000 for 2021 and $1,015,000 for 2022.

The Company's forecasted amounts of $6,699,000 for 2021 and $4,944,000 are excessive and unsupported. Therefore, I recommend that the Commission remove the excess amount of $5,703,000 and $3,929,000 from the Company's forecast capital expenditures for 2021 and 2022, respectively.

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[36] Exhibit AG-1.8 includes DR ST-CE-687.

12. Distribution Capital Expenditures Adjustments - Summary

Q. WHAT IS THE TOTAL AMOUNT OF THE CAPITAL EXPENDITURE ADJUSTMENTS FOR THE ELECTRIC DISTRIBUTION PROGRAMS THAT YOU RECOMMEND?

A. For the Distribution programs discussed above, I recommend a total disallowance of forecasted capital expenditures of $129,358,000 for 2021 and $191,547,000 for 2022. These amounts translate into a rate base reduction of $225.1 million.

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 $169.6 million for Power Generation plant in 2019, and forecasted $129.5 million for 2020, $297.9 million for 2021, and $443.7 million for 2022. 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. Hardy Spillway and 2020 Solar Bid Event Projects

On lines 23 and 35 of page 8 of Exhibit A-12 (SAH-3), Schedule B-5.2, the Company included 2021 forecasted capital expenditures of $8,000,000 for remediation work on the Hardy Auxiliary Spillway and $14,623,000 for solar project costs from a 2020 bid event.

Similarly, for the same projects in 2022 on lines 22 and 32 of page 9 of Schedule B.2, the Company included $19,850,000 of forecasted expenditures for the Hardy Auxiliary Spillway remediation and $119,624,000 for costs pertaining to the 2020 solar bid event. In total, for the two years, the Company has forecasted $27,850,000 to remediate the Hardy Auxiliary Spillway and $134,247,000 for solar costs from the 2020 bid event.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE FORECASTED CAPITAL EXPENDITURES FOR THE HARDY SPILLWAY AND THE SOLAR COSTS?

A. In response to discovery, the Company stated that the projects and costs underlying the Hardy Auxiliary Spillway remediation work and the solar projects from the 2020 bid event have not yet received management approval. In its response, the Company stated that approval is not expected until November 2021. Exhibit AG-1.9 includes the Company's response to discovery request ST-CE-083.

Without full approval by executive management, and potentially the Finance Committee of the Board of Directors, the proposed capital expenditures are premature for inclusion in rate base in this case. If approval has not been received yet, it means that the projects have not yet been fully reviewed and vetted by executive management. Therefore, it is possible, if not likely, that the forecasted amount and timing of the projects can vary significantly. Customers should not start paying in new rates beginning in January 2022 for projects that have not yet been fully vetted and approved until November 2021.

I recommend that the Commission remove the forecasted amounts pertaining to the Hardy Auxiliary Spillway and the 2020 solar bid event in the total amount of $21,636,000 for 2021 and $133,252,000 for 2022. These amounts have been reduced for the related contingency costs previously disallowed above.[37]

2. Hydro Units

Beginning on page 82 and going through page 93 of his direct testimony, Company witness Scott Hugo discusses work to be performed at several of the Company's hydro power generating facilities. As shown on page 1 of Exhibit A-12, Schedule B-5.2, line 7, the total forecasted capital expenditures for 2021 and 2022 are $34.9 million and $59.9 million, respectively. Pages 8 and 9 of the same exhibit and schedule show specific project costs for each of the facilities.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION FOR THE FORECASTED CAPITAL EXPENDITURES FOR THE HYDRO PROJECTS?

A. The hydro power generating facilities are relatively small in size in generating capacity. Page 6 of Mr. Hugo's testimony shows the list of hydroelectric facilities ranging in size from less than 1 Megawatt (MW) to 33 MW with most of them having less than 7 MW of generating capacity. All the facilities were built before 1937. Most of the facilities are over 100 years old and in need of significant remediation relative to the power generated.

[37] Exhibit A-12, Schedule B-5.2, page 8, lines 23 and 35 for 2021, and page 9, lines 22 and 32 for 2022.

Given the large amount of capital expenditures of nearly $95 million forecasted over the 2021-2022 period, in discovery the Company was asked if it had performed a cost/benefit analysis to determine whether the proposed capital investments in these facilities are economically sound. In response, the Company stated that no cost/benefit analysis had been performed and the planned projects were proposed to comply with Federal Energy Regulatory Commission (FERC) requirements and other internal safety and operating requirements in order to continue to operate the facilities. Exhibit AG-1.10 includes the Company's responses to discovery requests AG-CE- 909 and 910.

The objective of performing the cost/benefit analysis is not to comply with FERC's or other operating/safety requirements, but to determine if remediating, upgrading or replacing large components at the hydro facilities make economic sense. If the analysis shows that completing the proposed projects makes economic sense, then they should be done. However, if the analysis shows that the projects are not economical, then the projects should not be done and the facilities should be retired or other less costly remediations should be undertaken.

The Company has not performed this basic and fundamental economic analysis to justify spending nearly $95 million over the next two years and probably considerably more in future years. Without a favorable economic analysis at each of the facilities, the Commission should not approve the majority of the proposed capital expenditures for 2021 and 2022.

With the exception of the Alcona Emergency Spillway project, which appears to require an emergency remediation, the other projects on page 8, lines 21 to 26, of Exhibit A-12, Schedule B-5.2, should be removed from the forecasted capital expenditures for 2021 in this rate case. After adjusting for the Hardy Auxiliary Spillway remediation costs and the contingency costs previously disallowed above, the remaining amount to be removed from the 2021 forecasted expenditures is $12,920,000. Similarly, for the 2022 capital expenditures, the amount to be removed is $22,893,000 consisting of the amounts on page 9, lines 17 through 27, except for line 22, of the same exhibit and excluding contingency costs previously disallowed.

I recommend that the Commission remove the amount of $12,920,000 and $22,893,000 from the Company's forecasted capital expenditures for 2021 and 2022, respectively.

3. Overhead Cost Allocation

On page 101, lines 12-25, of his direct testimony, Mr. Hugo discusses the inclusion of $3.0 million of overhead costs in the forecast capital expenditures for 2021 that were previously assigned to a large project whose cost decreased significantly from the original estimate. In response to discovery question AG-CE-914, the Company stated that it had prepared its long-term financial plan assuming that the solar project at issue would be $36 million higher than was ultimately negotiated.[38] Therefore, although it had initially allocated more overhead costs to this project, in preparing this rate case the Company allocated less

[38] Exhibit AG-1.11 includes DR AG-CE-914.

overhead due to the lower project cost. The Company now seeks to retain and recover the overallocation of overheads to the 2021 forecasted capital expenditures as a separate item.

Q. WHAT IS YOUR ASSESSMENT AND RECOMMENDATION REGARDING THE EXCESS OVERHEAD COSTS?

A. The $3.0 million of excess overhead costs should be removed from the 2021 forecasted capital expenditures. The allocation issue described by Mr. Hugo in his testimony and discovery response is an internal Company problem caused by the timing of when the Long-Term Financial Plan was prepared relative to when the ultimate cost for the large project was determined. This timing issue will resolve itself once actual overhead costs are allocated to the actual project costs in 2021. The discovery response in Exhibit AG-1.11 addresses the initially forecasted overhead allocation but does not consider the final allocation of overheads that will occur in 2021 once actual costs are incurred and the actual allocation of overhead takes place.

The Company allocates, or should be allocating, overhead costs to capital projects based on the Company labor costs spent on construction projects versus O&M expense and other activities. Therefore, once actual construction costs are incurred in 2021, the overhead costs will be allocated on the lower actual costs incurred for the solar project at issue. As a result, the proper amount of lower overhead costs should be allocated to the project once actual costs are incurred in 2021, and the additional $3.0 million of overhead costs will not be capitalized to plant and rate base.

I recommend that the Commission remove the $3.0 million of excess overhead costs from the Company's forecasted 2021 capital expenditures.

4. 2020 Actual Power Generation Capital Expenditures

In discovery, the Company was asked to provide the actual capital expenditures incurred for the year 2020 in the power generation area. In response to discovery request AG-CE-594, which is included in Exhibit AG-1.12, the Company reported that in 2020 it incurred $124,336,000 of actual capital expenditures in the power generation area. This amount is $5,203,000 lower than the forecasted amount of $129,539,000 included in this rate case.

The $5,203,000 of costs not spent in 2020 in the Power Generation area should not be included in rate base. 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 2020. Therefore, I recommend that the Commission remove the $5,203,000 from rate base in this rate case.

D. Operations Support - Capital Expenditures

On line 1 of Exhibit A-12 (SJB-1), Schedule B-5.5, the Company forecasted capital expenditures for Asset Preservation of $33.1 million for 2020, $24.3 million for 2021, and $83.4 million for the year 2022. In comparison, the Company incurred capital expenditures of $20.5 million in 2019. Included in the forecasted capital expenditures for 2021 and 2022 are capital expenditures for several new service centers, a new Unified

Control Center (UCC), the Marshall Sub-Metro Training Building/Center, and proposed modifications to office space for employees returning to work locations post-Covid-19 restrictions. Exhibit A-19 (SJB-3) shows the specific expenditures. In my testimony below, I will address each of those projects.

With regard to the UCC, although Company witness Scott Bartholomew sponsored testimony and exhibits on the capital expenditures, Company witness Brenda Houtz provided additional details on the project in her testimony.

1. New Service Centers

On lines 14, 15 and 17 of Exhibit A-19 (SJB-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 2021 is $3,830,000. For the year 2022, the total forecasted amount is $34,775,000. Mr. Bartholomew discusses the three service centers beginning on page 12 of his direct testimony.

Q. WHAT IS YOUR ASSESSMENT OF THE FORECASTED CAPITAL EXPENDITURES FOR THE THREE SERVICE CENTERS?

A. From reviewing Mr. Bartholomew's testimony, it is apparent that the service centers are still in the early design phase and still undergoing conceptual programming. In discovery the Company was asked to provide a project timeline for each center showing all the phases of the project, the current phase of the project, and the planned completion date. In response, the Company could not provide the requested information and instead referenced the capital expenditures by year in Exhibit A-27 (SJB-11).[39] The exhibit has no specific timeline and does not identify the current phase of each project or its completion date. The exhibit simply shows the total “ballpark” cost estimate for each center and the allocation of costs to the electric and gas businesses by year. In total, between 2020 and 2024, the three service centers are forecasted to cost more than $127 million with most of those costs being allocated to the electric business.

In discovery, the Company was also asked to provide the number of employees and operating/administrative functions that will be housed at each service center. The information provided in discovery responses AG-CE-563, 567 and 569 raises 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, Customer Experience & Technology, and Transformation.[40]

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 a large

[39] Exhibit AG-1.13 includes DR AG-CE-562, 565, and 568.
[40] Id. includes DR AG-GE-563, 567, and 569.

service centers to house functions, such as HR, IT, Public Affairs and Rates and Regulatory Affairs, that could be performed at the Company's headquarters.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR 2021 AND 2022 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 stage of design and development. Furthermore, the timing of when the forecasted expenditures are likely to occur in 2021 and 2022 is suspect. The Company has not provided a timeline for start and completion of the projects or a completion date.

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. In its order of December 17, 2020 in Case No. U-20697, the Commission rejected the Company's proposed capital expenditures for the three centers for 2020 and 2021 as not being adequately supported.[41] Nothing has changed in this rate case filed approximately two months after the Commission order. The forecasted capital expenditures for 2021 and 2022 are still premature and not adequately supported.

[41] MPSC Case No. U-20697, order dated December 17, 2020 at page 101.

Therefore, I recommend that the Commission remove the forecasted capital expenditures for the three service centers of $3,830,000 for 2021 and $34,775,000 for 2022.

2. Marshall Training Center

On lines 21 of Exhibit A-19 (SJB-3), the Company included $3,125,000 of forecasted capital expenditures for 2022 for the new Marshall Training Center. Beginning on page 26 of his direct testimony, Mr. Bartholomew describes the objectives of what the Company seeks to achieve with this new training center and generally what it entails. The project will require constructing a new building at a location not yet disclosed. Although the name Marshall may indicate the city location, which is approximately 30 miles west of the Company's headquarters in Jackson, Michigan, and a 35-minute car ride. The project will also entail construction of underground vaults, tunnels, and manholes with underground electricity cables. The Company also plans to develop training manuals and videos at the facility.[42]

Q. WHAT IS YOUR ASSESSMENT OF THE FORECASTED CAPITAL EXPENDITURES FOR THE MARSHALL TRAINING CENTER?

A. According to Mr. Bartholomew's testimony, the Company seeks to replicate what it calls best training practices by building a new training center with the ability to conduct hands-on training that replicate real-life situation in underground vaults. The Company's refers

[42] Scott Bartholomew direct testimony at page 31.

to it as a holistic approach. Although hands on training simulating real-life conditions can certainly be effective and productive in instilling appropriate skills, the question is why a new building is needed to accomplish this goal. The question also arises how the Company has been able to impart the appropriate training up to now without the Marshall Training Center.

Underground vaults with electric cables and switches are not new. They have existed for decades, if not more than a century, in both older and newer cities. It is not clear what has changed that now requires a new building and additional facilities to accomplish that training. Even assuming that building underground vaults, tunnels, manholes and electric cabling for training is now necessary, the question still remains why these facilities cannot be built at or near existing buildings and training centers owned by the Company, thus avoiding the construction of a new building at a cost in excess of $3.0 million. In fact, the Company has not explained or justified the need to construct a new building to house a new training center for the limited purposes that it would serve.

In discovery, the Company was asked to provide a detailed timeline for the construction of the Marshall Training Center with start and completion dates for each phase of the project and the costs to be incurred during each phase. In response, the Company provided a summary schedule by quarter with related amounts to be spent. The information shows that the Company has not yet performed any programming and design of the facility and does not expect to do so until the later part of 2021. Construction would not occur until the second half of 2022 if the major milestones shown in the discovery response can be relied on. Exhibit AG-1.14 includes discovery response AG-CE-573 with this information.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE MARSHALL TRAINING CENTER?

A. The conclusion I draw from the limited information provided by CECo is that the project has not yet been fully defined and is premature to be included in rate base in this rate case. Furthermore, the Company has not made a compelling case and has not adequately justified the need for the proposed facility or that other less costly alternatives have been evaluated.

Therefore, I recommend that the Commission remove the capital expenditures of $3,125,000 included by the Company in 2022 in this rate case.

3. Unified Control Center (UCC)

On lines 13 of Exhibit A-19 (SJB-3), the Company shows forecasted capital expenditures for the new UCC for 2021 and 2022 of $840,000 and $24,162,000, respectively. According to the testimony of Mr. Bartholomew, the total forecasted capital expenditures for this new facility from 2022 to 2024 are in excess of $83,000,000. Mr. Bartholomew dedicates a single page of testimony to describe key construction items for the project beginning on page 25 of his direct testimony and points to the testimony of Company witness Brenda Houtz for further details.

Q. WHAT IS YOUR ASSESSMENT OF THE FORECASTED CAPITAL EXPENDITURES FOR THE UCC?

A. Company witness Brenda Houtz expands further on the purpose for the UCC beginning on page 15 of her direct testimony. The testimony in this rate case mirrors her testimony filed in Case No. U-20697 where the Company attempted to justify the initial capital expenditure of $1.0 million to purchases land and do other project scoping. In that rate case, the Commission disallowed the forecasted capital expenditures and agreed with the Proposal for Decision and the AG arguments that the Company had not made a compelling case to receive approval for the projected capital expenditures.

Unfortunately, in this rate case the Company again failed to make a compelling and convincing case for the Commission to approve the proposed capital expenditures of approximately $25 million between 2021 and 2022. The Company fails to make a compelling case on multiple fronts. First, in response to a discovery request to provide a detailed timeline with start and completion dates for each phase of the project with related cost, the Company did not do so and provided a reference to Exhibit A-20 (SJB-4) which is simply an annual cost budget.[43] From the lack of a detailed timeline, it is evident that the project has not yet advanced to a point past the conceptual phase.

Second, in discovery, the Company was asked to provide the location of the proposed center. In its response, the Company stated that the location for the UCC has not yet been

[43] Exhibit AG-15 includes DR AG-CE-571.

determined.[44] This response reinforces the conclusion in the first point above that the project is still in the conceptual phase.

Third, according to another discovery response, the Company's plan is to consolidate four functions in the UCC with 195 employees.[45] This plan appears to be broader than the purpose of the UCC outlined at the bottom of page 16 of Ms. Houtz's direct testimony where she states "The UCC Project is aimed at bringing two of the major electric system and electric supply groups together and incorporating an EOC center function into a coordinated center." The Company has not made a convincing case as to why consolidating the four functions in the same center is necessary. In her testimony, Ms. Houtz points to potential work efficiencies, cost savings and risk reductions, but these are general statements with no specific or quantifiable benefits identified

Fourth, in discovery, the Company was asked to identify the work efficiencies and cost savings, and provide a cost/benefit analysis that presents the economic case to justify undertaking this project. In response, the Company stated it is still quantifying the cost savings and developing the cost/benefit analysis.[46] It is perplexing why the Company would propose undertaking a project with a cost exceeding $83 million before having completed a cost/benefit analysis that would justify undertaking such a project.

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[44] *Id*. includes DR AG-CE-572.
[45] *Id*.
[46] *Id*. includes DR AG-CE-872 and 874.

Fifth, in discovery the Company was also asked why with the technology tools currently available, which allow sharing of technical information instantaneously and visual interactions through computer screen, it is necessary for all functions to be at the same location? The Company's response attempts to justify the UCC by claiming that face to face collaboration provides a better environment for efficiency and knowledge sharing.[47] The response is not convincing. No evidence has been presented that the current dispersed centers are not functioning well and a consolidated location would provide superior results that justify $83 million in capital expenditures.

Sixth, with regard to the Company's argument that a purposely built facility with a hardened building and backup utilities would reduce risk of interruption of operations in case of a major catastrophic event, the argument is counter-intuitive. If a catastrophic event were to occur at or near the new UCC location, it is still possible that all the operations within the center could cease to operate. Therefore, the current dispersed locations offer a lower risk, because in case of a catastrophic event most likely only one location could cease to operate instead of all of them at the same time. To this point, the Company stated that after it builds the UCC, it would build redundant facilities at other locations.[48] In other words, the UCC is not the ideal solution that the Company seeks and would likely revert to a solution with multiple facilities which it already has.

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[47] *Id*. includes DR AG-CE-873.
[48] Id. includes also DR AG-CE--873

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE UCC?

A. The Company has not made a compelling case and has not adequately justified the need for the proposed UCC as a cost-effective alternative to the existing control centers. Furthermore, the project is in the very early conceptual phase and not sufficiently developed to permit the inclusion of the proposed capital expenditures in this rate case.

Therefore, I recommend that the Commission remove the capital expenditures of $840,000 and $24,162,000 included in the Company's 2021 and 2022 forecasts, respectively.

4. Return to Work Facilities Upgrades

On lines 20 of Exhibit A-19 (SJB-3), the Company included forecasted capital expenditures for 2021 and 2022 of $4,025,000 and $5,677,000, respectively, for potential workspace modifications related to COVID-19 restrictions that the Company may face upon the return of employees to their work locations. Mr. Bartholomew discusses this proposed project beginning on page 31 of his direct testimony.

Q. WHAT IS YOUR ASSESSMENT OF THE FORECASTED CAPITAL EXPENDITURES FOR THE RETURN-TO-WORK PROJECT?

A. Mr. Bartholomew's testimony is long on general concerns with having a safe work environment, but short on details as to what specifically the $9.7 million in capital expenditures proposed for 2021 and 2022 will be spent on. He discusses complying with

CDC and MIOSHA rules and guidelines but does not specifically identify what they require and what specific modifications are necessary. His testimony assumes that the workplace restrictions and CDC/MIOSHA guidelines that existed at the beginning of 2021, when his testimony was prepared, will still exist in the second half of 2021 when Company employees will begin to return to work. For example, in response to discovery, he refers to the CDC guideline of maintaining 6 feet of physical distance between building occupants.[49] However, the CDC and MIOSHA have relaxed some of the social distancing rules as more individuals have been vaccinated and will continue to be vaccinated. The whole idea of having a vaccine is for people and workers to return to normal or near normal work activities that existed pre-COVID.

Instead, the Company's proposal seems to ignore the existence of a vaccine or the natural immunities that certain workers have obtained from exposure to the virus and wants to impose costs on customers that may not be necessary. In discovery, the Company was asked to identify specifically what the forecasted capital expenditures will be spent on. In response to two separate discovery requests, the Company could not identify anything specific other than to state that it would undertake "Workspace modifications to support physical distancing and collaborative work between onsite and remote personnel." It also stated that it would modify current floor plans to accommodate a more modular and open

[49] Exhibit AG-1.16 included DR AG-CE-578.

floor space.[50] Neither of these explanations provide any specific expenditure items that can be analyzed and appropriately assessed.

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

A. The Company has not provided sufficient information to adequately justify the need to spend $9.7 million on workplace modifications to address physical distancing requirements. It is likely that the requirements assumed at the time the testimony and proposed expenditures were prepared will no longer be in place when employees begin to return to work.

Therefore, I recommend that the Commission remove the forecasted capital expenditures of $4,025,000 for 2021 and the $5,677,000 for 2022 from this rate case filling. To the extent that the Company may need to incur certain, still unspecified costs, to comply with workspace restrictions in 2021 and 2022, the Company can request recovery for those costs in the next rate case.

5. 2020 Actual Facilities Capital Expenditures

In discovery, the Company was asked to provide the actual capital expenditures incurred for the year 2020 in the Facilities area. In response to discovery request AG-CE-581,

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[50] *Id*. includes DR AG-CE-576 and 579.

which is included in Exhibit AG-1.17, the Company reported that in 2020 it incurred $28,522,000 of actual capital expenditures in the Facilities area. This amount is $5,050,000 lower than the forecasted amount of $33,572,000 included in this rate case.

The $5,050,000 of costs not spent in 2020 in the Facilities area should not be included in rate base. 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 2020. Therefore, I recommend that the Commission remove the $5,050,000 from rate base in this rate case.

E. Fleet Services - Capital Expenditures

On line 1 of Exhibit A-12 (ASC-1), Schedule B-5.6, the Company forecasted capital expenditures for Transportation Equipment of $32.7 million for 2020, $69.5 million for 2021, and $40.2 million for the year 2022. In comparison, the Company incurred capital expenditures of approximately $35.4 million in 2019. Included in the forecasted capital expenditures for the year 2021 are capital expenditures of $27.3 million for additional vehicles and equipment for a planned increase in employees in the LVD Electric Distribution area, and $7.5 million for a new Telematics fleet management system. For 2022, the forecasted capital expenditures include $20.5 million for additional vehicles and equipment for a further planned increase in employees in the HVD Electric Distribution area.[51]

In his direct testimony, Company witness Adam Carveth discusses the level of capital expenditures, as well as his proposal to increase capital spending to accelerate the replacement of the Company's fleet of cars, trucks, and equipment. Mr. Carveth is the latest of the Company's three witnesses who have requested an accelerated replacement of the transportation fleet in the last four rate cases for both the electric and gas businesses. In the last electric rate case No. U-20697, the Commission rejected the Company's proposed increases in capital expenditures for accelerated fleet replacement and set the amount of capital expenditures for the test year at an historical level of $17.5 million plus an inflation factor adjustment.

In addition to Mr. Carveth's direct testimony, the Company also filed the direct testimony of Christopher Shaffer, president of Utilimarc. In 2020, Utilimarc was commissioned by CECo to update the analysis of the Company's transportation fleet prepared in 2017.

Q. WHAT IS YOUR ASSESSMENT OF THE FORECASTED CAPITAL EXPENDITURES FOR THE TRANSPORTATION FLEET FOR 2021 AND 2022?

A. With regard to the base amount of capital expenditures to replace failing vehicles and equipment, as well as to provide vehicles for the organic growth in the business, the

[51] Exhibit AG-1.18 includes Company workpaper WP-ASC-1 showing the capital expenditures detail components by forecast period.

Company has proposed $34,667,000 for the year 2021 and $19,698,000 for 2022. The 2022 amount corresponds to the Even Replacement scenario presented by Mr. Schafer on page 4 of Exhibit A-102, which includes the results of the 2020 Utilimarc study.

For the 2021 forecasted amount there is no explanation or justification provided in Mr. Carveth's direct testimony. It is perplexing why the Company would propose to spend nearly $35 million in 2021 to replace end of life vehicles and equipment when the 2020 study performed by Utilimarc concludes that an expenditure level of $19.7 million in 2022 is the appropriate level of spending to achieve the required replacement rate. The Company's fleet continues to have a high availability rate averaging in excess of 97% and maintenance and repair costs remain relatively stable year over year.

Therefore, I find the higher 2021 capital expenditure amount of $34.7 million unsupported and unjustified. I recommend that the Commission remove the amount of $14,969,000, which is the excess of the forecasted amount over the 2022 baseline of $19,698,000 shown on page 4 of Exhibit A-102 for the Even Replacement Scenario.[52]

Q. WHAT IS YOUR ASSESSMENT OF THE INCREMENTAL SPENDING OF $27.3 MILLION PROPOSED BY THE COMPANY FOR 2021 AND THE $20.5 MILLION FOR 2022 TO PROVIDE TRANSPORTATION EQUIPMENT TO NEW

[52] Exhibit AG-1.18, WP-ASC-1, Lifecycle (Base) Capital Expenditures of $34,667,000 - $19,698,000 from page 4 of Exhibit A-102 = $14,969,000.

EMPLOYEES HIRED FOR ADDITIONAL ELECTRIC DISTRIBUTION FIELD WORK?

A. The Company has proposed $27.3 million of additional transportation equipment purchases in 2021 to supplement the base amount of transportation equipment purchases forecasted for the year. The additional purchases apparently are to provide vehicles to new employees who will be working on the LVD line system. Similarly, the Company proposed an additional $20.5 million increase for purchases of additional vehicles to perform potential incremental work on the HVD line system.

These additional amounts are relatively large expenditures to provide new equipment for new hires relative to the base purchases for replacement equipment needed by the existing pool of employees. On page 23 of his direct testimony, Mr. Carveth identifies the $27.3 million as a component of the total amount of capital expenditures forecasted for 2021 but provides no further explanation or justification of this large expenditure amount.

On page 27 of his testimony, Mr. Carveth briefly discusses the $20.5 million of incremental expenditures for the Electric Operations Workforce Expansion and defers to the direct testimony of Mr. Richard Blumenstock without a specific page reference. A review of the 303 pages of Mr. Blumenstock's direct testimony, which has no table of contents, did not identify any discussion of a Workforce Expansion program or any requirements for large increases in vehicles and equipment for 2021 and 2022.

In response to discovery, the Company provided a list of 224 vehicles and pieces of equipment it has forecasted it would purchase in 2021 for a total amount of $27.4 million.[53] Additionally, the Company also disclosed that it would hire 72 new employees in 2021 and 2022 to perform incremental LVD line work.[54] If we assume that the 2021 purchases will be made to provide sufficient transportation equipment to 144 new employees over the two years, the proposed purchases still exceed the number of employees by 80 units, even assuming a liberal one-to-one relationship of vehicles to employee.

In other words, the number of planned transportation fleet purchases in 2021 in comparison to the number of new employee hires do not match and do not appear reasonable. Furthermore, in the response to discovery request ST-CE-227 dated April 26, 2021, the Company stated that the projected units in the list of vehicles and equipment to be purchased are currently under review to ensure they meet the required field application.[55] Therefore, the list of equipment items to be purchased does not adequately support the incremental forecasted capital expenditures for 2021.

With regard to the 2022 incremental capital expenditures, the Company was asked to provide the details supporting the forecasted capital expenditures of $20.5 million. In response, the Company provided a list of 40 items with no dollar amounts.[56] Therefore, it is not possible to validate what makes up the $20.5 million.

[53] Exhibit AG-1.19 includes DR ST-CE-227 with attachment.
[54] *Id*. includes DR ST-CE-239.
[55] Exhibit AG-1.19.
[56] *Id*. includes DRs AG-CE-928, ST-CE-234 and 240.

In summary, the 2021 and 2022 forecasted incremental capital expenditures for additional transportation fleet purchases to support the potential expansion of the Distribution workforce are not adequately documented or supported by the Company. Therefore, I recommend that the Commission remove the $27,320,000 and $20,500,000 from the Company's forecasted 2021 and 2022 capital expenditures, respectively.

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

A. Although Mr. Carveth identifies $7.5 million of capital spending on this project on page 25 of his direct testimony as part of the $69.7 million in capital expenditures requested for 2021, he does not provide an explanation or justification for this amount.

However, in Case No. U-20697, beginning on page 27 of his direct testimony, Company witness Kyle Jones discussed the Telematics fleet monitoring and management system in some detail. The Telematics devices and technology allow the Company to use the transportation fleet more efficiently, and as result reduce operating and capital costs. 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.

In response to discovery in Case No. U-20697, the Company 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. As I stated in my testimony in Case No. U-20697, 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-1.20 includes the Company response to discovery request U20650-AG-CE-350 with the related pertinent attachment.

In discovery in this case, the Company was asked to provide a status report on the implementation of Telematic devices and technology into the Company's transportation fleet. In response, the Company reported that the installation of the Telematic devices is 82% completed and it is on track to spend the $7.5 million in 2021 in the electric business as forecasted. In the discovery response, the Company also reaffirmed the cost savings presented in Case No. U-20650 and included in Exhibit AG-1.20 in this rate case.[57]

As I stated in Case No. U-20650 and U-20697, the cost savings that the Company will generate from the implementation of the Telematics system will more than pay for revenue requirement from the capital expenditures added to rate base. The Company has not included those cost savings in the revenue requirement in this rate case. Therefore, I recommend that the capital expenditures of $7,506,000 for 2021 for the Telematics system be removed from rate base in this rate case.

Q. WHAT IS YOUR OVERALL CONCLUSION AND RECOMMENDATION?

[57] Exhibit AG-1.21 includes DR AG-CE-926.

A. The Company has not adequately supported the large amount of base capital expenditures forecasted for 2021. Also, the Company has not provided evidence to support the incremental capital expenditures for 2021 and 2022 to increase the transportation fleet to meet increased needs from the Distribution Workforce Expansion. Furthermore, the implementation of the Telematic system will generate sufficient cost savings to offset the cost of the capital expenditures for the project.

Therefore, I recommend that the Commission remove the total amount of $34,826,000 for 2021 and $20,500,000 for 2022 from the Company's forecasted capital expenditures.

F. Information Technology Projects - Capital Expenditures

In Exhibit A-12 (JDT-6), Schedule B-5.3, the Company shows total capital expenditures for Information Technology (IT) infrastructure and various projects. For 2020, the Company forecasted capital expenditures of $51.5 million, for 2021 it forecasted $58.6 million, and for 2022 it forecasted $77.2 million. Capital expenditures for 2019 were $52.5 million. Included in the capital expenditures for 2021 and 2022 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 43 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 discussed later in my testimony are, it 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. Customer Relationship Management (CRM) System

Beginning on page 19 of her direct testimony, Company witness Anita Griffin describes the CRM system and identifies $1.76 million of capital expenditures for 2022 along with $292,000 of O&M costs. Ms. Griffin describes the CRM system as a necessary technology tool that enables the Company to combine relevant information to effectively manage its customer relationships and interactions.

Q. WHAT IS YOUR ASSESSMENT OF THE CRM SYSTEM AND RELATED CAPITAL EXPENDITURES FORECASTED BY THE COMPANY?

A. Ms. Griffin's testimony describes the CRM as a system that aggregates information from multiple areas in a common data base and as a result improves work efficiencies, avoids duplication of data, and helps with customer communication. However, her testimony does not explain how the Company will use the system and what specific incremental revenue it will generate from improved business customer interactions. The benefits listed on page 20 of her testimony list four areas of peripheral benefits, but do not get to the core of why the Company should implement a CRM system.

In discovery, the Company was asked to identify the cost of the project from inception to completion. In response to discovery request AG-CE-952, the Company identified the total capital expenditures for the project at $10.3 million from 2020 to 2023, with $5.7 million of those costs assigned to the electric business and the remainder to the gas business. In addition, the Company forecasted O&M expenses of $7.6 million from 2019 to 2025 to support the system development and subsequent support past implementation with $6.2 million of those costs applicable to the electric business. The forecasted O&M expense pertaining to this project for 2022 is $1,441,000.[58]

[58] Exhibit AG-1.22 includes DR AG-CE-952. The amount of O&M expense identified in the discovery response is $1,441,012 for 2022. This amount is much larger than the $292,000 identified on page 19 of Ms. Griffin's direct testimony. For purposes of disallowance of the O&M expenses later in my testimony, I used the higher number provided in the discovery response.

The combined capital and O&M costs to develop and implement this system are nearly $18 million of which the electric business has been assigned $11.9 million. For this large investment, the Company can only identify peripheral cost savings. Most businesses that implement a CRM system do so primarily to drive more sales and revenue, not just to achieve administrative and operating cost savings. At its core, a CRM system is a sales tool not an administrative tool as used by the Company.

In response to discovery, the Company stated that it had performed a cost/benefit analysis. The analysis shows that over a 10-year period the present value of the capital expenditures exceeds the present value of the cost savings by approximately $4.0 million. This result is based on a total project capital expenditure amount of $7.8 million instead of $10.3 million as disclosed in response to discovery. The Company also assumed that O&M cost savings would reach $1.7 million in 2022.[59] No information has been disclosed to support that amount of cost savings. The cost/benefit result would be even worse if the correct capital expenditures were used and the O&M savings were set at a more realistic amount. In any case, the analysis shows that the project is not economically justified and should not be recovered in rates.

Therefore, I recommend that the Commission remove the project capital expenditures of $1,841,000 for 2020, $1,734,000 for 2021 and $1,758,000 for 2022. In addition, the

[59] Id. includes DR AG-CE-953.

Commission should remove $1,441,000 of O&M expense related to the project for the 2022 test year.

2. Commercial & Industrial Account Management System

Beginning on page 11 of her direct testimony, Ms. Griffin briefly describes the Commercial and Industrial Online Account Management project. The purpose for this project is to add additional features to the Company's customer service system to allow large commercial and industrial (C&I) customers with multiple accounts to combine accounts under a single log-in. It would also allow those customers to assign authorizations for managers at various customer locations to have access to their specific accounts. Currently C&I customers have access to only each individual account within the Company's self-service customer web portal and utilize a third-party portal to complete the consolidation of multiple accounts.

The Company has included $6.61 million of capital expenditures in the test year in this rate case for the project, plus $1.19 million in O&M expense. In response to discovery, the Company has stated that the total project cost from inception to completion will be $10.8 million, spanning from 2022 to 2023, with $7.2 million assigned to the electric business. Additionally, the Company would incur $2.1 million in O&M expense over the two years for a total project cost of nearly $13.0 million. In the same discovery response, the Company also disclosed that the project had not yet started as of June 2021 and that project scoping and definition would not be done until February 2022 with project completion in March 2023.[60]

Q. WHAT IS YOUR ASSESSMENT OF THE C&I ACCOUNT MANAGEMENT SYSTEM AND RELATED EXPENDITURES FORECASTED BY THE COMPANY?

A. There are two basic problems with the Company's proposed system and the forecasted costs for the 2022 test year. First, the cost of this new system, or added feature, is disproportionate to the benefits derived from it. This system is being built to address at most 20,000 C&I customers at a cost of nearly $13.0 million. The Company serves about 3.6 million customers about equally split between gas and electric customers. The 20,000 C&I customers represent less than 1% of the total customer base. It is not appropriate to burden the majority of customers with $13 million of costs for a marginal benefit to be derived by a small group of customers. Furthermore, the Company has already developed an alternative means to allow C&I customers to combine their accounts through a third-party portal, which it pays for.[61] Although, it may not have all the conveniences that the new system proposed by the Company, this alternative seems to be a more cost-effective solution than spending $13.0 million on a new system with limited use.

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[60] Exhibit AG-1.23 includes DR AG-CE-941.
[61] Id. includes DR AG-CE-942.

Second, the project has not yet been fully scoped and defined. It is at the conceptual stage and premature for inclusion in rate base. Therefore, I recommend that the Commission remove the $6,610,000 of capital expenditures for the 2022 project test year and the related O&M expense of $1,190,000.[62]

3. Bill Design & Delivery Transformation Project

Beginning on page 27 of her direct testimony, Ms. Griffin briefly describes the Bill Design and Delivery Transformation project. According to her testimony, the project has three primary components: (1) a bill redesign for the most common rates and billings, (2) some software replacements to resolve certain billing limitations, and (3) flexible bill printing with outsourcing of bill delivery to reduce internal costs. The Company has included $6.91 million of capital expenditures in the test year in this rate case for the project, plus $1.66 million in O&M expense.

In response to discovery, the Company has stated that the total capital project cost from inception to completion will be $16.6 million, spanning from 2022 to 2023, with $11.7 million assigned to the electric business. Additionally, the Company would incur $5.4 million in O&M expense over the two years for a total project cost of $22.0 million. In the same discovery response, the Company also disclosed that the project is in the early

[62] The amounts for capital expenditures and O&M expense differ between Ms. Griffin direct testimony on page 11 and DR AG-CE-941 in Exhibit AG-1.23. For purposes of the proposed disallowances for this project, I used the amounts from Ms. Griffin's direct testimony.

planning phase as of June 2021 and that project scoping and definition would not be done until February 2022 with project completion in June 2023.[63]

Q. WHAT IS YOUR ASSESSMENT OF THE BILL DESIGN AND DELIVERY TRANSFORMATION PROJECT AND RELATED EXPENDITURES FORECASTED BY THE COMPANY?

A. This project suffers of the same two basic problems as the previous project. First, the cost of this new system, or added features, is disproportionate to the benefits derived from it. In response to discovery, the Company stated that it last performed a bill redesign in late 2015. It is not clear why another bill redesign is necessary five-years later. The Company's reasoning that it wants to capitalize on the latest state-of the-art functionality is disconnected from the reality of spending $22.0 million to achieve marginal benefits.[64]

Some of the other features and functionalities identified by the Company may seem appealing and may generate some cost savings, but they need to also be evaluated against the economic value derived from the system implementation. In response to discovery, the Company provided the cost/benefit analysis for the project. The analysis shows that the present value of the costs for the project dwarfs the present value of the cost savings through the year 2030. The present value of the costs of the project is $25.3 million versus $7.1 million in cost savings.[65] The difference between those two amounts is an economic

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[63] Exhibit AG-1.24 includes DR AG-CE-956.
[64] *Id*.
[65] Id. includes DR AG-CE-957.

loss of $18.2 million. This is not a prudent investment and any cost recovery should be rejected by the Commission.

Second, the project has not yet been fully scoped and defined. It is at the conceptual stage and premature for inclusion in rate base. Therefore, I recommend that the Commission remove the $6,910,000 of capital expenditures for the 2022 project test year and the related O&M expense of $1,660,000.

<u>4. Customer Self-Service Mobile Application Project</u>

Beginning on page 12 of her direct testimony, Ms. Griffin describes the Customer Self-Service Mobile Application project. According to her testimony, the Company wants to deploy a mobile phone application that allows customers to access its website to review their bill, manage bill payments, report outages, analyze energy usage, and perform other functions. The Company believes that more customers will use the online functions if offered through a mobile app and estimates 300,000 downloads of the mobile app in the first year it is available. The Company has included $1.59 million of capital expenditures in the test year in this rate case for the project. No O&M costs were disclosed for this project.

In response to discovery, the Company has stated that the total capital project cost from inception to completion will be $29.6 million, spanning from 2020 to 2026, with 67% of the cost, or $19.9 million assigned to the electric business. In the same discovery response, the Company also disclosed that the initial implementation of the project is in the execution phase.[66] From the multi-year span of the project, it appears that the Company expects to implement different features and functionality over time over the 7-year life of the project.

Q. WHAT IS YOUR ASSESSMENT OF THE CUSTOMER SELF-SERVICE MOBILE APPLICATION PROJECT AND RELATED CAPITAL EXPENDITURES FORECASTED BY THE COMPANY?

A. The cost of this new system is disproportionate to the benefits derived from it. In response to discovery, the Company stated that in 2019 and 2020 it performed surveys with customers subsequent to calls taken by customer service representatives, which indicated that approximately one-third of the customers would have used a mobile app if available instead of calling the Company.

These surveys were not performed in a scientific and controlled basis and should be viewed with significant skepticism. Without providing the customer with a complete comparison of what the app may offer, the navigation difficulties usually associated with going through multiple screens, and without informing customers that the app would cost nearly $30 million, which they would pay through their electric and gas bills, the customer is not well informed to provide an intelligent response to the flash survey.

The Company's also relied on guidance from Accenture that in the first year of implementation of the mobile app it would experience 300,000 downloads. The basis for

[66] Exhibit AG-1.25 includes DR AG-CE-943.

this estimate was not disclosed and the source of this information should be viewed with a high degree of skepticism. Accenture sells services to implement mobile applications, such as the one that the Company seeks to implement. Their opinion is biased by the desire to sell services to utilities who are ready and willing to implement those apps.

Ultimately, the decision should come down to whether the added functionalities and conveniences offered to customers make economic sense. With this project, a large part of the Company's motivation to undertake the project is to reduce customer calls and save on operating expenses in addition to offering more customer conveniences. In response to discovery, the Company provided the cost/benefit analysis for the project. The analysis shows that the present value of the costs for the project are significantly higher than the present value of the cost savings through the year 2026. The present value of the costs of the project is $14.5 million versus $1.7 million in cost savings.[67] The difference between those two amounts is an economic loss of $12.8 million. The cost/benefit analysis uses different capital expenditures than shown in discovery response AG-CE-943 included in Exhibit AG-1.25. The cost benefit analysis only includes $9.2 million of capital expenditures instead of the $29.6 million over the 2020 to 2026 timeframe. If the higher capital expenditures are included, the cost/benefit results would be even worse. From this economic analysis, it is readily apparent that this project is not a prudent investment and any cost recovery should be rejected by the Commission.

[67] *Id.* includes DR AG-CE-945.

Therefore, I recommend that the Commission remove the 67% of the capital expenditures for this project applicable to the electric business from 2020 through 2022 based on the amounts shown in discovery response AG-CE-943 included in Exhibit AG-1.25. The proposed disallowance amounts are $2,892,000 for 2020, $5,098,000 for 2021, and $2,374,000 for 2022.[68]

5. Alternative Payment Methods & Customer Loyalty Program

Beginning on page 33 of her direct testimony, Ms. Griffin describes the Alternative Payment Method and the Customer Loyalty programs. According to her testimony, the Alternative Payment pilot program would allow customers to pay their bills with additional new digital payment methods, such as Apple Pay, Google Pay, Pay Pal, Venmo, Amazon Pay and Alexa Pay. The Customer Loyalty Program would give customers free online loyalty rewards for paying their bills on time, for participating in eBill, and by enticing customers to engage in online activities with the Company, such as using the energy dashboard. In her testimony, Ms. Griffin identified $2.5 million of capital expenditures to launch the new programs in 2022, and $2.2 million of O&M expense for the projected test year.

In response to discovery, the Company disclosed that the total capital cost of the programs will be nearly 5.0 million in 2022 including the portion applicable to the gas business.

[68] The 2022 capital expenditure amount on page 12 of Ms. Griffin's direct testimony does not match to the amount calculated by taking 67% of the total amounts from DR AG-CE-943. Also, Ms. Griffin did not identify any capital expenditures for the project for 2020 and 2021 in her testimony. Therefore, the amounts from DR AG-CE were used in the calculation of the disallowance amount for all three years.

Similarly, the total O&M expense to implement the programs will be $4.4 million.[69] Therefore, the combined costs of the programs, including both capital and O&M costs, will be $9.4 million.

In the same discovery response, the Company also disclosed that the Customer Loyalty project had not yet started as of June 2021 and that project scoping and definition would not be done until February 2022 with project completion in July 2022. With regard to the Alternative Payment Methods pilot program, the scoping and definition of the program will not start until August 2021 with implementation forecasted for December 2021. The Company also anticipates the pilot to be successful and has forecasted that it would scope and define the final Alternative Payment program in April 2022 with implementation in August 2022.[70]

Q. WHAT IS YOUR ASSESSMENT OF THE CUSTOMER LOYALTY PROGRAM AND ALTERNATIVE PAYMENT PROJECT AND THE RELATED CAPITAL EXPENDITURES FORECASTED BY THE COMPANY?

A. It is not entirely clear why the Company seeks to implement a customer loyalty program and what the ultimate objective is. Typically, customer loyalty programs are implemented by companies in competitive industries to attract and retain customers in order to gain and retain market share and increase revenues. In the case of Consumers Energy, operating a

[69] Exhibit AG-1.26 includes DR AG-CE-961.
[70] *Id*.

monopoly business, residential and small commercial customers, to whom such as program would be directed, cannot leave the utility company serving them and go to another utility unless they move from their current location. Offering rewards to gain loyalty so that customers continue to take service from the utility does not seem to apply to customers of utility companies. Similarly, it seems unnecessary to reward customers for paying their bill on time when the Company imposes late payment charges on customer bills for payment past the due date.

The Company estimates that 3%-4% of its customers will participate in the Loyalty program. The basis for this estimate was not disclosed. From the Company's statements, it appears that the Company may consider increasing the amount of the rewards to increase participation over time.[71] However, it is not clear how the cost of the program can be economically justified.

With regard to the Alternative Payment Methods project, the desire to chase the latest technological advancements and offerings need to be weighed against the cost and benefits of implementing those new payment methods. The Company expects 50,000 customers to initially use some of these new payment options after implementation. The Company did not disclose the source or basis for this estimate. The 50,000 customers, if accurate, represent approximately 1.5% of the company's total customer bases of 3.6 million for both the gas and electric businesses. Such a limited use of these features needs to be

[71] *Id*.

weighed and economically justified against spending millions of dollars in capital investments and operating expenses.

I response to discovery, the Company stated that it had not performed a cost/benefit analysis at this time and expects to prepare an analysis once the pilot has been approved and is in the planning and design phase. The sequence here is backwards. The cost/benefit analysis needs to be prepared upfront before millions of dollars are spent on pilots and other activities for a project that may be so far removed from being economical that it may not even need to go to a pilot phase.

In conclusion, the proposed Customer Loyalty and Alternative Payment programs have not been adequately supported and justified. Furthermore, the programs have not been sufficiently defined and developed, and it is premature to include them in rate base.

Therefore, I recommend that the Commission remove the $2.5 million of capital expenditures and $2.2 million of O&M expense included by the Company in the 2022 test year in this rate case.

6. ARP – Workstation Asset Refresh

Beginning on page 55 of his direct testimony, Mr. Jeffrey Tolonen discusses the ARP-Workstation Asset Management program. This program entails the purchase of new computers and periodic replacement of desktop computers, laptop computers, computer monitors, and other related devices. On page 9 of Exhibit A-110 (JDT-9), the Company lists the various devices with quantities and dollar amounts. For 2021 and 2022, the Company has forecasted a major escalation in new purchases and replacement of older units with $5,839,512 of capital expenditures in 2021 and $7,380,051 in 2022. In comparison, the Company incurred capital expenditures of $2,596,742 in 2019 and $4,872751 in 2020 as allocated to the electric business.

Q. WHAT IS YOUR ASSESSMENT OF THE ARP-WORKSTATION ASSET REFRESH PROGRAM AND THE RELATED CAPITAL EXPENDITURES FORECASTED BY THE COMPANY?

A. In his direct testimony, Mr. Tolonen stated that the Company uses a 4-year replacement/ refresh cycle for the devices in this equipment category in order to avoid hardware failures and software compatibility problems. In discovery, the Company was asked to explain the reasons for the increased capital expenditures forecasted for 2021 and 2022 over prior years. The Company was also asked to explain why it uses a short 4-year replacement cycle and not a longer cycle, such as 5 to 7 years. In response, the Company stated that the increase in capital expenditures in 2021 and 2022 is due to increases in scheduled replacements according to the refresh cycle, previous year deferrals of equipment replacements, and incremental unit cost increases.[72] The response is very general and not sufficiently informative.

[72] Exhibit AG-1.27 includes DR AG-CE-896e.

If the Company has deferred replacements of devices, it means that it is not complying with its own 4-year refresh cycle. In the discovery response, the Company never addressed the alternative of extending the replacement cycle to 5-7 years. However, in response to another discovery request, the Company stated that a 4-year replacement cycle is necessary because the devices are critical to support customer interactions and business operations. In the discovery response, the Company stated that as devices age the number of problems and failures increase. To support its argument, the Company added an industry chart of unknown origin to the discovery response showing that the number of hardware incidents increase with time.[73]

However, the numbers shown are not relative to any industry-wide population of devices from which these numbers were derived. If the numbers shown are for millions of devices, the number of incidents each year are insignificant. Likewise, the incremental percentage of problems or failures could be insignificant between a 4-year replacement cycle and a longer 6-year replacement cycle. The Company has not provided any useful information to support its practice that a 4-year replacement cycle is necessary.

My analysis of page 9 of Exhibit A-110 shows that the Company forecasted to replace significantly more devices in 2021 and 2022 than it did in 2019 and 2020. This is not a consistent replacement/refresh cycle as Mr. Tolonen espouses. For example, between 2021 and 2022 the Company proposes to replace 3,775 laptops and 10,000 monitors. In

[73] Id. incudes DR AG-CE-887.

comparison, in 2019 and 2020, the Company replaced 2,313 laptops and 2,362 monitors. The difference in units replaced between those years is significant.

Due to the inconsistent spending over the four years from 2019 to 2020, a reasonable forecast for the ARP-Workstation program for 2021 and 2022 should be based on the average spending for 2019 and 2020 of $3,734,746.[74] To determine the forecasted capital expenditures for 2021 and 2022, I have applied a 2% inflation factor to the base amount. Therefore, for 2021, I calculated forecasted capital expenditures of $3,809,441 and for 2022 capital expenditures of $3,885,630.

The Company's forecasted capital expenditures of $5,839,512 for 2021 and $7,380,051 for 2022 are excessive. Therefore, I recommend that the Commission remove $2,030,071 and $3,494,421 from the Company's forecasted capital expenditures for 2021 and 2022, respectively.

7. Digital-Hybrid Cloud and Data Center Migration

Beginning on page 11 of his direct testimony, Mr. Tolonen describes the Digital-Hybrid Cloud and Data Center Migration project. According to Mr. Tolonen, the purpose for this project is to optimize data center assets and future asset purchases by migrating or retiring system applications out of existing data centers and into cloud services. This program would reduce operational costs for running IT services and increase cloud capabilities to

[74] Exhibit A-110, page 9, line 72: ($2,596742 + $4,872,750) ÷ 2 = $3,734,746.

improve efficiency and the quality of IT services. The Company has forecasted $3,213,366 in capital expenditures for the projected test year and $1,534,865 for O&M expense.

Given the objectives of the project of reducing operating costs and increasing efficiencies, the Company was asked to provide the cost/benefit analysis showing that this project was economically justified. In response, the Company provided only a cost/benefit ratio of 0.18 as justification for the project with no supporting data and calculations. In the discovery response, Mr. Tolonen also stated that the cost benefit/analysis could not be provided because it resides within the Company's Business Planning System.[75] This is in contrast to the cost/benefit calculations provided by Ms. Griffin for the other IT projects discussed above.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THIS PROJECT AND THE RELATED EXPENDITURES FORECASTED BY THE COMPANY?

A. The Digital-Hybrid Cloud and Data Center Migration project is supposedly a cost-saving move by the Company. The costs to achieve the migration to cloud computing should be justified based on cost savings achieved against current operations. Otherwise, there should not be a compelling reason to migrate to cloud computing. The cost/benefit analysis, properly performed to compare the net present value of cost savings over capital

[75] Exhibit AG-1.28 includes DR AG-CE-890.

expenditures, should be determinative to establish whether the migration is a sound economic decision or not. Unfortunately, the Company's refusal to provide the requested information has prevented the validation of the Company's cost/benefit calculation and a determination that the capital expenditures and O&M expenses forecasted by the Company are appropriate and should be approved.

Therefore, I recommend that the Commission remove $3,213,366 from the Company's forecasted 2022 capital expenditures and also $1,534,865 from the forecasted test year O&M expense.

8. Business Planning Optimization

Beginning on page 13 of her direct testimony, Ms. Karen Gaston describes the Business Planning Optimization project. According to Ms. Gaston, Company employee and a third-party review have found that the SAP system cost structure is too complex and difficult to extract financial data from, and also difficult to understand the source and method of cost allocations. The cost structure and allocation procedures were established as part of the system configuration when the SAP accounting system was developed. Apparently, the Company did not structure the cost functions and allocations correctly and now wants to spend $882,000 between capital expenditures and O&M expenses to fix the problem.

The problem that needs to be fixed was the result of the Company's own doing when it built and configured the SAP accounting and reporting system. Customers have already paid for the cost to implement the SAP system and should not pay again to fix problems caused by the Company.

Therefore, I recommend that the Commission remove $351,600 of capital expenditures and $330,000 of O&M expense for the 2022 projected test year.

9. Core Human Capital Management Transformation

Beginning on page 14 of her direct testimony, Ms. Gaston describes the Core Human Capital Transformation project. According to Ms. Gaston, the project will provide foundational technology improvements to achieve a best-in-class Human Resources department and provide services to enable co-workers to deliver hometown service for the Company's customers. This description does not identify what the system will actually achieve. Unfortunately, the rest of Ms. Gaston's testimony on this project is replete with cliches, buzz words, and a hodge-podge of general statements. The project will require $1,592,748 in capital expenditures in 2022 and $72,600 in O&M expense.

Ms. Gaston's response to discovery, did not shed more light on what critical new functionality this new system will add that the existing system does not have.[76] Generally, the discovery response makes broad statements without any specific data or functions identified. For example, she states that the current HR data has a high cost and time requirement without identifying what they are. Similarly, she states that the current HR data system does not have the technical structure to accommodate new employee job and

[76] Exhibit AG-1.29 includes DR AG-CE-862.

organizational data without specifying what the technical structure should be. With regard to the new technology system, she states that it will provide a solution to collect and maintain core HR data in a standard, best-in-class structure without defining what that structure is. Similarly, she states that the new system will provide more efficient, cost effective and timely maintenance without identifying what it is.

In other words, it is not possible to extract from the Company's description of this proposed system what new critical and valuable functionality will result from the implementation of the system to justify spending nearly $1.6 million.

The Company has not adequately justified the need for the new Core Human Capital Management Transformation project. Therefore, I recommend that the Commission remove the $1,592,748 from the Company's 2022 forecasted capital expenditures.

10. Integrated Business Planning and Reporting

Beginning on page 16 of her direct testimony, Ms. Gaston describes the Integrated Business Planning, Forecasting, Resource Planning, and Managerial Reporting project. According to Ms. Gaston, the project will improve the Company's short-term and long-term financial planning processes, forecasting, resource planning, and operational and managerial reporting. From Ms. Gaston's testimony it is not clear what the shortcomings are with the Company's current system and processes, other than her statement that current planning processes consist of siloed views. Apparently, the current system requires some manual effort to consolidate data and report it in a different format. The cost to implement the new system will require $3,646,795 of capital expenditures in 2022 and $335,280 in O&M expense also in the projected test year.

In her testimony, Ms. Gaston lists a number of functions that the new system will perform, which mostly duplicate functions performed by the current planning and reporting system. However, from the testimony, it appears that the Company expects the new system to result in a more efficient planning and reporting process that will reduce costs and create other benefits.

In response to discovery, the Company stated that it anticipates annual cost savings of $1.6 million beginning in 2025 with some of the saving coming from lower O&M costs and others from lower capital expenditures.[77] The Company did not provide any supporting details to allow a review and determination of the validity of the anticipated cost savings. Certainly, identifying $1.6 million of anticipated cost savings is not equivalent to performing a complete cost/benefit analysis. Therefore, proper justification to undertake the project has not been provided.

In response to discovery, the Company also stated that it has issued a request for information on available systems that could meet its requirements but has not issued a request for proposal as of the end of April 2021 and expects to do so in 2022.[78] From this response, it is evident that the project is still in the preliminary conceptual phase, and thus premature to include in rate base in this rate case.

[77] Exhibit AG-1.30 includes DR AG-CE-252.
[78] *Id.*

Therefore, I recommend that the Commission remove $3,646,795 from the Company's 2022 forecasted capital expenditures and $335,280 from forecasted O&M expense for the test year.

11. 2020 Actual IT Capital Expenditures

In discovery, the Company was asked to provide the actual capital expenditures incurred for the year 2020 in the IT area. In response to discovery request AG-CE-589, which is included in Exhibit AG-1.31, the Company reported that in 2020 it incurred $49,988,000 of actual capital expenditures in the IT area. This amount is $1,520,000 lower than the forecasted amount of $51,508,000 included in this rate case.

The $1,520,000 of costs not spent in 2020 in the IT area should not be included in rate base. 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 2020. Therefore, I recommend that the Commission remove the $1,520,000 from rate base in this rate case.

G. 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)
Contingency Costs	$ 27.3
Distribution Plant	320.9
Power Generation	198.9
Information Technology	47.6
Operations Support	81.5
Fleet Services	55.3
Total	**$ 731.5**

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 $731.5 million and reduce average rate base by $488 million, as shown in Exhibit AG-1.32. The resulting effect of the lower rate base from the reduction in capital expenditures is a reduction in the revenue deficiency of $53.1million.

IV. Depreciation Expense

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

A. In Exhibit AG-1.32, 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 $30.5 million. I recommend that the Commission reduce the Company's depreciation expense by this amount for the projected test year.

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 in Exhibit AG-1.33 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 2022. 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-1.33 has been increased by $380 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 $380 MILLION AND OFFSET THIS CHANGE WITH LOWER COMMON EQUITY OF $380 MILLION?**

A. The Company has proposed a permanent capital structure with a common equity component of 52.0%. While this percentage is slightly less than the 2019 historical test year percent of 53.16%[79], 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%.[80]

Q. PLEASE EXPLAIN YOUR ASSESSMENT OF THE COMMISSION'S DIRECTIVE TO THE COMPANY TO REBALANCE ITS CAPITAL STRUCTURE.

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

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[79] Exhibit A-14 (MRB-2), Schedule D1a, page 1.
[80] Exhibit AG-1.36 shows that the peer group average equity ratio is 45.2%. .

> 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.

In the same vein, in its December 17, 2020 order in Case No. U-20697, the Commission adopted the Commission Staff's (Staff) proposed 51.11% common equity ratio as a transition to its desired goal of having Consumers Energy reach a 50/50 balanced capital structure by stating "Specifically, the Commission finds that the Staff's recommendation keeps Consumers on track to rebalance its capital structure as the Commission previously ordered, while allowing Consumers to maintain its wide access to capital markets to be reasonable."

Company witness Andrew Denato discussed the Commission's stated objective of a balanced capital structure 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 March 2021 by approximately three and one-half years.

In contrast, in the Company's last gas rate case (Case No. U-20322) and electric rate case (Case No. U-20697), the Company argued for a 52.5% common equity level. Now, in this case, the Company proposes a 52.0% common equity ratio. It is also noteworthy to point out that in his direct testimony in this case, Mr. Bleckman does not address either the expiring PPAs nor the deceleration in capital expenditures, which were major considerations in Mr. Denato's proposal in Case No. U-18424.

Also in past rate cases, the Company has argued that the effects of the TCJA requires a higher common equity ratio. Yet, 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. 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 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, fund a larger portion of the expenditures with internally generated cash, and issue less debt, if it is truly 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.

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

A. The cash flow to debt coverage ratios in the chart and related testimony beginning on page 15 of Mr. Bleckman's direct testimony are inaccurate and highly misleading. Mr. Bleckman's chart suggests that based on a 51.1% common equity ratio and a 9.9% ROE (authorized in Case No. U-20697), 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. In fact, the Company's current credit rating by Moody's is "A1" which is three notches above the "Baa" rating.

Additionally, the chart shows that the Company would move from the "Intermediate Risk" category to the "Significant Risk" category according to the Standard & Poor's (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 debt rating.

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

A. According to Exhibit A-30 (MRB-8), the Company's senior secured debt is rated as "A" by S&P. Furthermore, on page 4 of its January 27, 2021 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.[81]

Page 4 of the report also shows the 2020 estimated FFO to debt coverage ratio for Consumers Energy in a range of 20% to 22%. Even Mr. Bleckman's own Exhibit A-33 (MRB-11) shows a coverage ratio of 20.9% after adjusting 2019 results for the 9.90% ROE and common equity ratio from case No. U-20697. The 20.9% coverage ratio is well above the 15% "downgrade threshold" referenced by S&P in the section of the report quoted above. Accordingly, there is no anticipated risk of a S&P downgrade of the Company's debt due to cash flow changes.

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

A. The Company's debt was previously rated Aa3 by Moody's and in May 2021 Moody's downgraded the Company's debt to "A1". It is important to understand that the prior Moody's rating was out of line with the credit ratings assigned to the Company's debt by S&P and Fitch which are "A" and "A+", respectively. These ratings reflect the middle

[81] Exhibit AG-1.41 includes S&P report dated January 27, 2021 provided by Company in discovery response AG-CE-615.

and top end of the "A" category. The new "A1" rating by Moody's still places that rating one notch above S&P and at par with Fitch's rating. The prior Moody's rating was at the lower end of the stronger "AA" category. The higher credit rating by Moody's reflects that rating agency's level of comfort with the Company's risk profile and accords the Company's an added cushion against any downgrade below the middle "A" rating level.

Moody's attributed the change in ratings to a number of factors including lower credit metrics, the heavy debt load at parent company CMS Energy, and a lower ROE and a lower common equity ratio from rate case decisions. The last two items are attributed to the fact that authorized ROEs and the common equity ratio were lowered at a slower pace in Michigan compared to other states, which had accorded Moody's the flexibility to keep the Company's debt rating in the lower end of the "AA" range. Once the Commission began to appropriately lower the authorized ROE for Michigan utilities and realigning the capital structure to lower the revenue requirement burden on customers, Moody's lowered its lofty rating to be more in line with the other rating agencies.

Although Mr. Bleckman and Company witness Wehner like to characterize the recent Moody's credit rating downgrade to "A1" as a catastrophic event, nothing could be further from the truth.

Q. HAVE THE OTHER TWO RATING AGENCIES TAKEN ANY ACTION SINCE THE DOWNGRADE OF THE COMPANY'S DEBT BY MOODY'S?

A. No. As I explained above, Moody's new credit rating of "A1" for the Company's senior secured debt is still above the ratings assigned by S&P and at par with the Fitch rating, so I would expect no credit rating actions from the two rating agencies based on the current Consumers Energy credit outlook. As stated earlier, the higher Moody's debt rating accords the Company's an added cushion against any downgrade below the middle "A" rating level.

Q. MR. BLECKMAN'S EXHIBIT A-33 (MRB-11) SHOWS A 2019 MOODYS CFO PRE-W/C TO DEBT RATIO OF 18.9% FOR CECO AFTER SEVERAL ADJUSTMENTS. SHOULD THE COMMISSION BE CONCERNED THAT THIS RATIO MAY LEAD TO A DOWNGRADE OF THE COMPANY'S DEBT?

A. No. The Company's analysis is outdated and irrelevant at this time. First of all, 2020 results are now known, and the Company's debt has been re-rated by Moody's.

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

A. Yes. In Exhibit AG-1.42, I calculated the Company's key cash flow to debt coverage ratio for 2020 adjusted for the ROE and Common Equity ratio levels advocated in the Attorney General's case. I utilized the actual Moody's coverage ratio results for 2020 and adjusted these results for an ROE rate of 9.50%, and a 50% common equity capital ratio. I chose 2020 because this is the most recent data available from Moody's.

For my analysis of 2020 cash flow ratio results, I started with the actual data and coverage ratios as determined by Moody's for 2020 on line one of the exhibit. Next, on line 2, I added additional long-term debt to reflect a lower common equity level and adjusted the cash flow downward to reflect lower earnings. On line 3, I adjusted the cash flow downward to reflect a 9.5% ROE (vs. the 9.7% ROE actually achieved in 2020). The result of these adjustments is shown on line 4 with a 21.2% coverage ratio. This result is well above the Moody's 18% downgrade threshold shown on line 5. In the exhibit, I did not present the S&P cash flow coverage ratio results because the outcome would have been similar to the calculation I performed for the Moody's coverage ratio. With the S&P downgrade threshold being lower at 15%, the 21.2% coverage ratio is well above that threshold. My analysis shows that with a 50% equity ratio and a 9.5% ROE, the Company is far from facing a debt rating downgrade.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE CASH FLOW TO DEBT COVERAGE RATIOS THAT THE COMPANY USES AS JUSTIFICATION FOR PROPOSING A 52.0% EQUITY RATIO?

A. The premise put forth by Mr. Bleckman that the Company needs an equity ratio of 52.0% has no factual basis and is meritless. As I have shown in Exhibit AG-1.42, the Company has ample room in the 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 well above the minimum level 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 "A1" by Moody's is one notch higher than the "A" debt rating assigned by S&P. The higher Moody's credit rating is also the main reason for the higher minimum coverage ratio of 18% required by Moody's versus the 15% required by S&P. 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 52.0% equity ratio to avoid a potential downgrade because the cash flow to debt coverage ratios have weakened due to the enactment of the TCJA and other factors is a red herring. I suspect the real motivation to increase the amount of common equity in the capital structure is to expand the equity capital base on which the Company can get a return and as a result increase or maintain a higher level of earnings. The Commission should reject the Company's recommendation for a 52.0% common equity ratio and instead, it should adopt the Attorney General's recommendation for a balanced capital structure of 50% common equity and 50% long-term debt and preferred stock.

Q. WITNESS BLECKMAN ON PAGES 20 TO 22 OF HIS TESTIMONY ATTEMPTS TO JUSTIFY HIS PROPOSED 52% COMMON EQUITY RATIO BY NOTING THAT 52% IS EQUIVALENT TO A 50% OR 50.7% RATIO ON AN ADJUSTED BASIS AFTER CONSIDERING LEASES, SHORT-TERM DEBT AND SECURITIZATION DEBT. HOW DO YOU RESPOND?

A. With his claim that the 52% common equity ratio is equivalent to a 50% common equity ratio inclusive of leases, short-term debt, and securitization debt, Mr. Bleckman is trying to confuse the issue. The issue here is the common equity ratio in the permanent capital structure of the Company, which consists of only common equity capital, preferred stock and long-term debt. Leases, short-term debt and securitization debt are not part of the permanent capital structure of the Company.

The Commission was aware of the Company's use of leases, short-term debt, and securitization debt when it directed the Company to achieve a balanced permanent capital structure. Short-term debt and securitization debt along with the imputed debt for leases were in place when the Commission issued its directive in Case No. U-17990 for the Company to rebalance its capital structure. In fact, these financing instruments have been in place for decades before the Commission order in Case No. U-17990 and will continue to be in place in the future. The existence of these financing instruments is nothing new and do not provide a basis for the Company to now argue that somehow the capital structure inclusive of short-term debt, securitized debt, and imputed lease debt is equivalent to the permanent capital structure. In its directive in Case No. U-17990, the Commission addressed the rebalancing of the Company's permanent capital structure with equal amounts of common equity capital and debt and preferred stock.

The Company's premise that by adding short-term debt, securitized debt, and imputed lease debt to the permanent capital it has achieved a balanced capital structure has no merit.

The Commission should reject this argument out of hand as a deceptive attempt to confuse the Commission.

Q. MR. WEHNER DISCUSSES THE ISSUE OF CAPITAL STRUCTURE ON PAGES 22-25 OF HIS TESTIMONY AND SPONSORS EXHIBIT A-119 (TAW-3) SHOWING THAT THE CURRENT 51.1% COMMON EQUITY RATIO AND 9.9% ROE MAY BE INADEQUATE TO MAINTAIN THE COMPANY'S CREDIT RATINGS. WHAT IS YOUR ASSESSMENT?

A. The equation shown in Exhibit A-119 is defective and too simplistic for two reasons. First, there is no provision in his equation for deferred income taxes. Deferred income taxes represent more than 16% of the total regulatory capital structure supporting the Company's rate base and are projected to increase from $3.4 billion in the historical 2019 period to $3.8 billion in the projected test year. Yet, witness Wehner ignores this key source of funds for Consumers Energy in his equation.

Second, his depreciation component of 3.9% is understated, and it should be a higher rate. It is the Company's net plant (not its gross plant) that is being financed with debt and equity and deferred taxes. Multiplying this gross rate by the ratio of gross plant to net plant would correct this factor. Correcting his formula for these two factors would significantly change the results of the equation. Mr. Wehner's equation is unreliable for evaluating a utility'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 COMMON EQUITY RATIO OF THE PEER GROUP USED TO ASSESS THE COST OF COMMON EQUITY IS SLIGHTLY ABOVE 45%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE COMMON EQUITY RATIO FOR THE COMPANY.**

A. As shown in Exhibit AG-1.36, the average common equity ratio of the peer company group for 2020 was 45.2%. 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, to have consistency with the cost of equity capital derived from those peer group companies. The Company's proposed common equity capital ratio of 52.0% creates a disconnect that is not acceptable and is also more costly to customers.

Q ON PAGES 22 AND 23 OF HIS TESTIMONY, MR. BLECKMAN STATES THAT HIS PROPOSED 52% COMMON EQUITY RATIO IS NOT AS HIGH AS THE AVERAGE RATIO OF OTHER UTILITY COMPANIES. IS THERE ANY VALIDITY TO HIS CLAIM?

A. No. In discovery, the Company was asked if the equity ratios shown in Exhibit A-32 were average ratios over a period of time or specific levels at a moment in time. In response, Mr. Bleckman stated that the equity ratios were at "a moment in time." [82] Equity ratio at a point in time are not representative of the average ratios over a 12 or 13-month period, which is typically used for ratemaking. At a minimum, the Company could have calculated the equity ratios over a period of four quarters. More importantly, in the same discovery request, the Company was asked if the equity ratios in Exhibit A-32 represented the equity ratios in the capital structure of those utilities as set by the regulatory commissions in those companies' last general rate case. In response, Mr. Bleckman stated that he did not know.[83]

In other words, Mr. Bleckman first represents that the equity ratios of the utilities in Exhibit A-32 are comparable to the 52% equity ratio he seeks to obtain, but later admits they are not really comparable or cannot confirm that they are.

Therefore, the Commission should give no weight to the information in Exhibit A-32 and the related testimony by Mr. Bleckman based on this exhibit.

Q. IF THE COMPANY WERE TO BE DOWNGRADED ONE NOTCH BY MOODY'S FROM "A1" TO "A2", WHAT WOULD BE THE APPROXIMATE HIGHER COST THAT THE COMPANY WOULD INCUR?

A. For the sake of argument, if we assume Consumers Energy's debt was downgraded one notch by Moody's from its current credit rating, I estimate the additional cost would be

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[82] Exhibit AG-1.43 CECo's response to DR AG-CE-622.
[83] *Id.*

approximately 15 basis points on new long-term debt issued in the future. This means that the additional cost for a new 30-year $500 million bond issue could increase by $750,000 per year. However, this cost is dwarfed by the higher cost to customers from carrying a higher common equity balance at the 52.0% level proposed by the Company. As discussed below, the increase in the revenue requirement of having a common equity ratio of 52.0% versus a 50% ratio is $22.6 million annually.

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 52.0%?

A. The difference is approximately $22.6 million of additional revenue requirement, annually. This reflects (a) the difference between the pre-tax cost of common equity of approximately 14% versus the cost of long-term debt of 3.5%; (b) the Company's proposed rate base of approximately $12.9 billion; and (c) the percentage of total capital being shifted from common equity to long term debt.

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. For example, in this rate case, the Company shows on page 3 of Exhibit A-14, Schedule D-1a, the equity infusions from CMS for the four years 2019 to 2021. The equity infusions are more directly related to CMS raising debt capital than equity capital, as shown in the tables below.

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.[84] 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.

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

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 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.

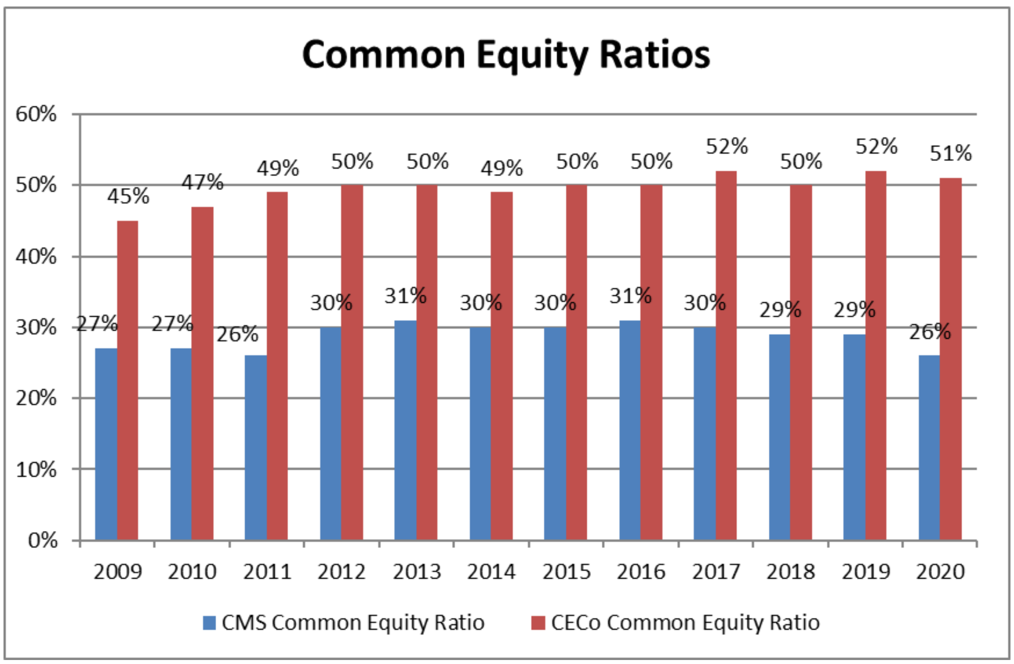
CMS Energy	
CMS Funds Available to Invest in Consumers Energy	**Billions**
Dividends from Consumers Energy	$ 2.6
Less: Dividends to CMS Shareholders	(1.9)
Less: Other CMS Parent Co. Interest & Other	(0.4)
Sub Total	0.3
Increase in Parent Company Debt	1.0
Other - CMS Equity Issued & Other	0.5
Funds For 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 five years ending in 2019, CMS parent-only debt has increased from $2.4 billion at year end 2014 to $3.5 billion at year end 2019.[85] While cash raised from the issuance of long-term debt at CMS is not immediately injected into

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

Consumers Energy, it is nonetheless being utilized in part to fund CMS's equity infusions into CECo.

The following chart displays the gap in equity capital between Consumers Energy and CMS over the years 2009 to 2020. In 2020, CMS' equity capital declined further to 26% of the permanent capital structure.



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%.

CMS and CECo's management are relying heavily on the capital structure of Consumers Energy to prop up the parent company's capital structure to an extent that it has become an indirect financial subsidy by the utility to its parent company and non-utility businesses.

The excessive debt and low common equity ratio at CMS (26% at year-end 2020 and down from 29% at year-end 2019) 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.[86] Similarly, page 2 of the Moody's report issued a year later on June 19, 2019 contains a substantially similar comment.[87] 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 wants to maintain a higher equity ratio in the capital structure that results in higher costs to customers.

[86] See Moody's Report, page 2 attached to Case U-20322 Staff Audit Request #11.
[87] See Moody's Report, page 2 attached to Case U-20697 AG-CE-098 under "Factors that could lead to a downgrade."

Q. HAVE THERE BEEN ANY CHANGES IN THE STATUS OF THE CREDIT RATINGS FOR CMS ENERGY IN 2020?

A. Yes. The Company declined to provide any rating agency reports for CMS Energy.[88] However, we know from Exhibit A-30 (MRB-8) that Moody's placed the ratings of CMS on Negative Outlook at some point in 2020. This action, which is likely reflective of the increasing debt at the CMS parent company level and deterioration of the common equity ratio to 26% at yearend 2020 are concerning given the interrelationship between the credit ratings of the parent company and Consumers Energy in the credit assessment of the rating agencies. A downgrade of the credit rating parent company could also result in a downgrade of Consumers Energy. The level of debt at the parent company poses the highest risk to a potential downgrade of Consumers Energy. CMS management needs to remedy the problem and reduce this risk.

It has become apparent that Consumers Energy cannot continue to prop up its parent company with higher amount of common equity capital. The reality is that while Consumers Energy currently has 51% to 52% of common equity capital in its permanent capital structure, CMS Energy at the consolidated parent level has only 26% common equity capital in its permanent capital structure. This means that the rest of CMS's other subsidiaries and the parent company have negative common equity capital that reduces the

[88] Exhibit AG-1.44 includes CECo's response to DR AG-CE-615.

Consumers Energy 51% to 52% common equity down to 26% at the consolidated parent company level.

CMS Energy's management needs to raise more common equity capital at the parent company and improve its common equity ratio to avoid negatively affecting the debt rating of Consumers Energy.

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

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

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE COMPANY'S CAPITAL STRUCTURE?

A. Despite the Company's protestations, the Commission should not be swayed from its stated objective of requiring that the Company capital structure reflect 50% common equity and 50% debt and preferred stock capital. The Commission has been very patient in giving the Company sufficient latitude to achieve a balance capital structure since its February 2017 order in Case No. U-17990. Time is now past due for the Company to comply.

I recommend that the Commission approve a 50% common equity ratio effective with its decision in this rate case.

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

A. I recommend an overall return on capital of 5.42%, which includes a return on common equity of 9.50%, as shown in Exhibit AG-1.34. Even though the average ROE calculated under the three methods discussed below is approximately 9.1%, 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 3.55%, which was developed by Company witness Bleckman.

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 amounts and 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-1.33.

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 5.42%.

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 6.76% 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-1.34.

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 method. To determine the cost of common equity, I have utilized three approaches to assess this cost: the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM) and the Utility Risk Premium approach.

While Exhibit AG-1.34 shows an average ROE of 9.06% 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 36 electric utility companies followed by the Value Line Investment Survey in its “Electric Utility Industry” sections. As set forth on my Exhibit AG-1.40, I have eliminated all but nine of these companies from peer group consideration. Companies with more than $17.5 billion in revenue and with less than $1.75 billion in revenue have been disregarded from consideration as being too dissimilar to Consumers Energy. Also, a number of the electric utility companies are involved in mergers or in selling assets or otherwise reorganizing and I have concluded that these companies are poor candidates to be in a peer group at this time. Companies with no growing dividends and those facing wildfire risk, nuclear build-out issues, and those facing off-shore wind construction risk are also not good candidates for the CECo peer group.

After removing those companies from consideration, my peer group includes a group of 9 companies shown in Exhibit AG-1.35, all of which have growing earnings and dividends. Exhibit AG-1.40 shows my analysis to arrive at this peer group of 9 comparable electric or combination gas and electric utilities.

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

A. My peer group is smaller than the one sponsored by Company witness Wehner and is more reflective of the electric utility business of Consumers Energy. Mr. Wehner has proposed using a group of 10 companies. In his peer group, he includes seven of the nine electric utility companies I have in my peer group, plus he has included three others that I find to be inappropriate.

Mr. Wehner has included Edison International in his peer group. This company has written off $4.25 billion of wildfire damage costs not covered by insurance over the last three years. Clearly, this company faces risks far beyond those of Consumers Energy[89]. Also, he includes DTE Energy in his peer group. DTE announced in early February 2021 (a month before Consumer Energy filing this case) its intention to "spin-off" approximately 20% of its assets (midstream, oil and gas) to shareholders later in 2021[90]. Given the declared intentions of DTE and the potential impact on its stock price, I find it inappropriate for inclusion in a peer group because of this pending transaction. The third company that is an unusual company for an electric utility peer group is NiSource. This is a natural gas distribution company with approximately 67% of its revenues coming from its natural gas distribution business.[91]

[89] See page 56 of the 2020 Edison International Form 10-K filed with the SEC.
[90] See DTE Energy February 19, 2021 Form 8-K filed with the SEC
[91] See Value Line Investment Survey page 543 from February 26, 2021.

Accordingly, 30% of the companies recommended by Mr. Wehner are not appropriate, and the Commission should reject this peer group. The peer group of nine companies I developed reflects a more comparable group of publicly traded companies.

<u>Discounted Cash Flow (DCF) Cost of Equity Method</u>

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

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

$$R = D/P + g$$

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

Regarding the growth rate in dividends, most practitioners rely on earnings growth as a substitute for this item and Mr. Wehner and I do as well in each of our analyses.

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-1.35. 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 19, 2021 to May

31, 2021. The annual dividend in column (d) is the projected average dividend level for 2021 and 2022 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 (2020 to 2025) per Value Line; and (2) the earnings growth estimates 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 9.32%.

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 will point out that the forecasted growth rates for the proxy group include some very high growth rates which in some cases are as high as 9.10%. These high growth rates appear to be the result of a temporary rebound in earnings from a low point in recent years. While these earnings may materialize in the short term, such high rates are not sustainable long-term growth rates for electric utilities given that customer and revenue growth continue to be barely in low single digits. As such, the results of the DCF analysis reflect a return on equity rate that may be somewhat higher than what investors currently expect in the long term. Nevertheless, I place a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other 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 9.32% rate I calculated is somewhat higher than the Company's "analyst-based" DCF calculation of 8.75% which is shown on page 5 of Exhibit A-14. The Company's estimate was performed at an earlier time than my estimate and contains a different peer group as discussed earlier and these factors have contributed to the Company's lower 8.75% DCF result.

<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 0.83.

Q. PLEASE EXPLAIN EXHIBIT AG-1.36 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-1.36 shows the results of the CAPM method based upon (1) a projected 2.75% risk-free rate; (2) the Betas of the companies in the Peer Group taken from Value Line; and (3) the 7.25% historical Market Risk Premium (R_p) return from the years 1926 to 2020 which is from the 2021 SBBI Yearbook published by Duff & Phelps.

For the risk-free rate, I used the forecasted 30-year U.S. Treasury bond rate for 2022 from the May 2021 Blue Chip forecast by,[92] This projected risk-free rate for 2022 coincides

[92] From Company discovery response AG-CE-616

with the timeframe when new customer rates will be in effect as a result of a Commission order in this rate case.

The result of my CAPM approach using the 2.75% risk-free rate is a cost of equity capital of 8.79% for the proxy group average.

Q. PLEASE ASSESS THE CAPM APPROACH.

A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios of stocks. As such, it can be useful. However, the key issue with CAPM is that it assumes that the entire risk of a stock can be measured by the "Beta" component 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, one can estimate the cost of common equity by estimating three components and adding them together. The three components are (1) the risk-free rate of return on 30-year U.S. Treasury Bonds; (2) the historical differential between yields of the rated utility bonds of the Company and the 30-year U.S. Treasury Bonds; and (3) the average return differential of utility common stocks over utility bonds[93].

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-1.37 shows the estimated cost of common equity under this approach and the resulting cost of equity rate of 8.82%. The exhibit shows the development of the ROE rate based on credit spread of utility corporate bonds rated "BBB" by Standard & Poor's which in included in the Blue-Chip estimate noted earlier and provided by the Company.

On line 3 of Exhibit AG-1.37, I start with the 4.30% forecasted BBB bond rate for the projected test year. To this rate, on line 4, I added the average spread of utility bonds over U.S. treasury bonds which is 4.52%. This rate is based on Mr. Wehner's Exhibit A-14 (TAW-1), Schedule D-5, page 9, line 89.

The sum of the result is a cost of equity of 8.82% as shown on line 5 of my exhibit.

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

[93] The first two components can be estimated on a combined basis as shown in my analysis.

A. Mr. Wehner presents the results of his Projected ECAPM, CAPM 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			
	DCF	CAPM	ECAPM	Risk Premium
Company Estimates	8.75%	14.88%	12.19%	14.90%
Attorney General Estimates	9.32%	8.79%	N/A	8.82%

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

A. The key differences between these ROE estimates is the risk premium rates utilized in the application of the models.

My calculations use the historical risk premiums for both the CAPM analysis and the Utility Risk Premium analysis. Witness Wehner utilizes a risk premium for his Projected ECAPM that is based upon projected returns in the stock market over the next five years based on data compiled from Bloomberg in December 2020. Mr. Wehner develops the projected risk premium of 11.25% for his ECAPM on page 11 of Exhibit A-14. This projected risk premium is four percentage points higher than the historical average risk premium of 7.25% for the years 1926 to 2020.

For Mr. Wehner's Projected CAPM, he relies upon the market risk premium developed for the ECAPM of 11.25% which I discussed in the preceding paragraph. This is his starting point. Then, instead of applying an average Value Line beta (approximately 0.8), he derives his own beta of 1.14 for utility stocks relative to the overall market. He then utilizes the 1.14 beta, the 11.25% risk premium and a 2.11% risk free rate to derive his CAPM ROE of 14.88%.

For his "so-called" Projected Risk Premium approach, he uses a risk premium of 11.3% calculated by taking the difference of utility stock returns from utility bond returns for two periods which are the years 1942 to 1951 and the years 2011 to 2020. Using the term "Projected" to label this method is a misnomer since it involves select historical information. The calculations for these short periods are shown on page 9 of his Exhibit A-14. The resulting risk premium from this short period is approximately 7 percentage points higher than the long-term historical average of utility stocks to bonds over 70 years.

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

A. In the case of his Projected Risk Premium method, Mr. Wehner is using two extremely short historical periods (the 1942 to 1951 period and the 2011 to 2020 period) to measure results and determine his risk premium. These two periods of time involve (a) the World War II recovery period from the "Great Depression"; and (b) the recovery years following the "Great Recession" of 2008 to 2009. As such, Mr. Wehner's results are upwardly biased and not reflective of long-term reality.

As for the Company's CAPM and ECAPM approaches, his utilization of Bloomberg data to project a risk premium as of December 2020 reflects the optimism among investors at that time over the projected short-term period of five years that the COVID 19 pandemic will end and that a substantial economic recovery will take hold. Also, Mr. Wehner's assumption for his CAPM that utility stocks are riskier than the overall market is at odds with conventual wisdom.

The forecasted ECAPM and CAPM 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. This would be akin to only selecting the positive return years in the Ibbotson series over the 95-year period 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 proposed.

For all of the above reasons witness Wehner's risk premiums for the Projected ECAPM, CAPM and Projected Risk Premium methods are seriously flawed and should be rejected.

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, and very low and perhaps even negative ROEs during periods of economic decline.

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 methods as unreliable and merely an attempt to produce a result that is more favorable to the Company. The Commission should give those ROE calculation methods 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.

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.[94] 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, Company witness Maddipati pointed out on page 58 of his direct testimony in Case No. U-18424 that the Maryland Commission stated that they found the DCF and ECAPM "helpful" in Case 9326. However, in a more recent case involving PEPCO (case 9418) with an order issued on November 15, 2016, the result is different. As shown in the summary positions articulated in the order in this case, no party involved in the proceedings, other than the utility, put forth an ECAPM ROE estimate. In this case, the Maryland commission basically adopted the Staff's position with no ECAPM estimate and rounded down the Staff's recommended ROE of 9.57% to 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 slightly lower ROE of 9.55%*

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

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…"* The Company has not provided any new information that shows other commissions are relying on this methodology.

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 (TAW-1), Schedule D-5, Mr. Wehner derives a 10.66% 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 just 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 2019 AND 2020.

A. Since 1990, the return on equity rates approved by regulatory commissions in electric cases has been on a steady decline from over 12.7% in 1990 to approximately 9.6% in 2018, 9.7% in 2019, and 9.4% in 2020. This decline has generally followed the significant decline in interest rates and the rate of inflation.

Exhibit AG-1.39 shows the ROEs granted by state regulatory commissions for U.S. electric utilities in 2019 and 2020. The majority of the 33 ROE decisions in 2019 and 41 decisions in 2020 are at rates well below 10%. As noted on page three of this exhibit, only 9 decisions in 2019 and 4 decisions in 2020 are at rates of 10% or greater. These higher rates 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). Also, the 10.5% ROE assigned to Georgia Power is a special situation involving the difficulties of this Company in completing two new nuclear generating facilities. Regulators in Georgia have been extremely supportive given the financial difficulties faced by the company.

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 9.90% excessive. The Company's proposed ROE rate of 10.50% is even further removed from reality and clearly unsupportable.

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-1.39 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-1.38 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 8.80%. Yet this group of companies has an average Market to Book common equity value ratio of nearly 2.0 times. The high Market to Book ratio reflects the fact that utilities are earning returns on book equity capital well above the investors' expected rate of return.

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, THE COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO AUTHORIZE A 10% ROE RATE. SHOULD STOCK MARKET VOLATILITY OR THE VIX INDEX BE A CONCERN IN ESTABLISHING A FAIR ROE RATE FOR THE COMPANY?

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

As a second point, in Exhibit AG-1.45, I have included a Value Line Funds article written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not risk. Mr. Appel goes on to say later in this article that "…volatility is only risk if you act during down times, that is, only if you sell a stock."

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 as much volatility as the general stock market. This is reflected in the average Beta value of 0.83 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. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE RETURN ON EQUITY RATE THE COMMISSION SHOULD USE IN THIS CASE.

A. In Exhibit AG-1.34, 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 8.79% at the low end, using the CAPM approach and 9.32% 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 9.32%. In this regard, on line 4 of Exhibit AG-1.34, 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 9.06%. To this base cost of equity capital, I have added an additional premium adjustment of 44 basis points to arrive at a recommended ROE rate of 9.50% for Consumers Energy's electric business in this rate case for the reasons explained below.

There are three reasons for this added premium of 44 basis points. First, the recent COVID-19 pandemic and the current state of the economy has increased business risk in general. The added premium to the calculated cost of equity provides a cushion to absorb the impact of this higher business risk.

Second, the extent to which investors anticipate changes in interest rates and the impact on stock prices is uncertain. As such, while the cost of common equity under the DCF approach is an accurate assessment of expectations for the forecasted test year and the long-term, the cost of equity methodologies may very well produce a different result should higher interest rates become a reality. In this regard, a potential 10% correction in utility stock prices due to higher interest rates or other events would produce approximately a 35 basis points increase in the cost of capital under the DCF approach.

Third, I understand that the Commission would be reluctant to grant a ROE at the 9.06% 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 9.90% granted to the Company approximately one year from the date of the Commission decisions in this case.

Q. IF THE COMMISSION APPROVES A 9.90% COST OF COMMON EQUITY IN THIS CASE (AS IT DID IN CASE NO. U-20697), WHAT IS THE COST TO CUSTOMERS COMPARED TO AN ROE OF 9.50%.

A. If the Commission were to grant a 9.90% ROE in this case versus a 9.50% ROE, the additional cost to customers is approximately $30 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 rate of no more than 9.50%.

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 (JRC-41), Schedule C-5, shows that O&M expenses are projected by the Company to be approximately $696.3 million for the future test year, an increase of $108.1 million, or 18% from 2019.

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 $101.1 million to a level of $595.2 million. Exhibit AG-1.46 shows a summary of my proposed O&M expense adjustments.

A. Inflation Adjustments - O&M Expense

Q. DO YOU AGREE WITH THE COMPANY'S RECOMMENDATION TO INCLUDE INFLATIONARY INCREASES IN THE PROJECTED O&M EXPENSE?

A. No. Approximately $30.6 million of the Company's requested O&M increase represents inflation increases estimated by the Company based on a blend of the Consumer Price Index (CPI) and a 3.2% forecasted annual wage increase for employees. The blended annual inflation cost adjustments are a combination of the labor wages increase and the forecasted CPI rates of 1.20% (2020), 2.50% (2021), and 2.30% (2022) applied to non-labor costs, as shown in the O&M exhibits of each Company witness. Some witnesses used slight variations of the wage increase for certain labor costs.[95] Exhibit A-13, Schedule C-5a summarizes the inflation cost adjustments for each of the operating and administrative units of the Company.

[95] CECo response to DR AG-CE-867.

The use of a "blended rate" which results from the use of both the CPI rate and wage increases has been rejected by the Commission in recent general rate cases.[96] More importantly and contradicting some of the Company's testimony in this case, CECo has not experienced across-the-board inflationary pressure on its operating costs. In fact, according to Company witness Michael Stuart, actual O&M costs have remained well below the inflation trend line from 2006 to 2019.[97] It is therefore difficult to understand why the Company would project inflation-related cost increases at annual rates ranging from 1.20% to 3.20% for 2020, 2021, and 2022.

The Company also has stated in testimony that investments in technology will result in increased operating efficiencies and reduction in O&M costs. These cost savings should offset any inflation. The Company has not provided any evidence that its operations are facing inflationary cost pressures on an overall basis that it cannot manage in the course of operating its business. It is more than likely, based on historical results, that the proposed $30.6 million in inflationary cost increases will not happen and that the Company can manage its business in a manner that it can offset any such costs. In such a case, the $30.6 million would provide a financial windfall to the Company.

I am aware that in prior rate cases, the Commission has allowed inflation cost increases for O&M expenses. However, the Commission has also rejected blended inflation cost

[96] MPSC Case No. U-20162 and U-18255.
[97] Michael Stuart direct testimony at page 6.

factors that include internal salary increases with CPI factors as proposed by the Company in this case.

As a matter of policy, it is not advisable to allow utilities to escalate costs for forecasted future inflation. It becomes in fact a self-fulfilling prophecy to increase future costs with inflation increases which then fuel and justify further inflationary trends. The Commission should only grant inflation cost increases when those increases are actually experienced and/or are likely to occur, and not because it has been past practice to do so. In this case, the evidence is clear that projected inflation cost increases are not warranted.

As such, I recommend that the Commission remove the entire $30.6 million of projected inflation increases from the future test year O&M expense as an unnecessary forecasted expense.

B. Alternative Inflation Adjustment

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

A. No. As discussed above, the Company recommends the inclusion of $30.6 million of expense for inflation increases. To compute this expense amount, the Company used a combination of forecasted wage increase rates and CPI rates. This results in blended rates of inflation, which are simply a creation of the Company. The Company controls the rate of wage increases it grants to its employees, including union employees, through collective bargaining agreements. It truly becomes a self-fulfilling prophecy for the Company to estimate and recover inflationary cost increases of more than 3% that it can then grant to its employees. It is important for the Commission to encourage fiscal restraint. Therefore, such internally projected inflationary cost increases should not be granted.

However, if the Commission is predisposed to allow the Company to recover projected inflationary cost increases, I recommend that the recovery amount reflect only the Consumer Price Index for Urban cities ("CPI-U") inflation factors or some other inflation factors comparable to the CPI. In discovery, the Commission Staff (Staff) requested the Company to recalculate the amount of inflation-related expense based on Staff's calculated rates of inflation which closely mirror the CPI rates and do not include a separate wage increase inflation rate. Staff's inflation rates are 1.24% for 2020, 2.47 for 2021, and 1.93% for 2022.[98] In response, the Company provide a schedule with recalculated inflation adjustments of $22,861 for 2020 through 2022. As shown in the attachment to Staff Audit Request SA-CE-260 in Exhibit AG-1.47 the difference between the Company's calculation and Staff's requested recalculation is a reduction in inflation-related expense of $7,777,000.

[98] Exhibit AG-1.47 includes CECo's response to Staff Audit Request SA-CE-260 with Attachment 1.

If the Commission decides to grant to the Company some amount of inflation-related O&M expense adjustment, I recommend that it approve only the $22,861,000 based on Staff's requested recalculation and remove $7,777,000 from the Company's forecasted O&M expense for the projected test year. In Exhibit AG-1.46, I included only the removal of this amount instead of the entire $30,638,000 inflation adjustment proposed by the Company.

C. Electric Distribution

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

A. As shown on line 61 of Exhibit A-44 (RTB-11), Distribution Operations expense was $174.0 million in 2019 and the Company has forecasted an expense of $185.0 million for the 2022 test year. In this exhibit, the Company also shows the historical expense by sub-program for the five-years from 2015 to 2019 and the five-year average expense amount. In discovery, the Company was asked to provide the same information with a column added to show actual O&M expenses by sub-program for the year 2020. In addition, the Company was asked to explain variances in expense by line item of 10% or greater between the 2022 forecast and the 2019 ended five-year actual average expense amount.

In response, the Company provided the requested schedule and noted that generally the increases reflect inflationary increases plus other forecasted expense adjustments. However, for any explanations of large variances, the discovery response referred to the direct testimony of Mr. Blumenstock.[99] The problem here is that Mr. Blumenstock's direct testimony explains the 2022 forecasts in broad statements with very few specifics, such as increases in work units to be completed or specific dollar amounts of expenses that are increasing from either 2019 or from the five-year average amount. The result is that there is no quantifiable support to the large increases in expenses at the program or sub-program level.

For example, as shown on line 8 of Exhibit A-44, for the Non-Forestry Reliability program, the 2022 expense is forecasted to increase by 142% over the five-year average amount. Similarly, other major program costs on lines 21, 31, and 53 for Operations, Maintenance and Metering, Field Operations, and Electric Planning are forecasted to increase from 21% to 58% in 2022 versus the five-year average amount from 2015 to 2019. These are large increases that have not been adequately supported by metrics or specific and quantifiable work activities. In my testimony below, I will address the significant increase in expense in each of the four programs mentioned. In my analysis, I will use the schedule in Exhibit AG-1.48 provided by the Company in response AG-CE-587 as Attachment 1, which includes the 2020 actual O&M expenses by program and sub-program. The line numbers in this schedule in Exhibit AG-1.48 match the line numbers in Exhibit A-44.

[99] Exhibit AG-1.48 includes DR AG-CE-587 and Attachment 1.

In this section of my testimony, I will also address the Service Restoration expense forecasted by the Company for 2022, which is sponsored by Company witness Brenda Houtz.

Non-Forestry Reliability – On line 8 of schedule in Exhibit AG-1.48, the Company shows $3,375,000 of expense for this program in 2019, $3,296,000 for the 5-year average, $4,198,000 for 2020 actual, and $7,985,000 for 2022. The 2022 forecasted expense is an increase of $3.8 million over the 2020 actual expense, or a 90% increase, and $4.7 million increase over the 5-year average, or an increase of 142%. Beginning on page 267 of his direct testimony, Mr. Blumenstock discusses this program and the sub-programs within the larger program.

Although dedicating seven pages of testimony to this program, the testimony is devoid of any specific information that justify the forecasted increase in expense for 2022, ranging from 90% to 142% in comparison to recent historical levels. It would be logical to expect some reference to specific increases in work units or work activities with related dollar amounts and explanations of why those activities are increasing to justify the large increases in expense at the sub-program level or at the overall program level. Without such detailed support and justification, it is not possible to determine whether the forecasted expenses are reasonable and should be approved.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S NON-FORESTRY RELIABILITY O&M EXPENSE FORECAST?

A. The Company's forecasted expense for the Non-Forestry Reliability program for 2022 is not adequately supported. As a result of the limited information provided by the Company, the only reliable basis for the 2022 expense forecast is to use the most recent actual expense. In this regard, I propose to use the highest expense amount between the 5-year average ended 2019 or the actual expense amount incurred in 2020. In this case, the 2020 actual expense of $4,198,000 exceeds the 5-year average amount of $3,296,000.

Therefore, I recommend that the Commission remove $3,787,000 from the Company's forecasted expense of $7,985,000 and approve the 2022 expense amount for Non-Forestry Reliability program in the amount of $4,198,000, plus any inflationary cost adjustment that the Commission wishes to grant, as previously discussed.

<u>Operations, Maintenance and Metering</u> – On line 21 of schedule in Exhibit AG-1.48, the Company shows $33,089,000 of expense for this program in 2019, $35,548,000 for the 5-year average, $28,786,000 for 2020 actual, and $43,059,000 for 2022. The 2022 forecasted expense is an increase of $14.3 million over the 2020 actual expense, or a 50% increase, and $7.5 million increase over the 5-year average, or an increase of 21%. On pages 274 to 288 of his direct testimony, Mr. Blumenstock discusses this program and the sub-programs within it. Although dedicating several pages of testimony to this program, the testimony is again devoid of any specific information that justifies the forecasted increase in expense in 2022 of up to 50% from recent historical levels. As stated earlier, it would be expected that the Company would provide substantial reference to specific increases in work units or work activities with related dollar amounts and explanations of why those activities are increasing to justify the large increases in expense at the sub-program level or at the overall program level. Without this detailed support and justification, it is not possible to determine whether the forecasted expenses are reasonable and should be approved.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S OPERATIONS, MAINTENANCE AND METERING O&M EXPENSE FORECAST?

A. The Company's forecasted expense for the Operations, Maintenance and Metering program for 2022 is not adequately supported. As a result of the limited information provided by the Company, the only reliable basis for the 2022 expense forecast is to use the highest expense amount between the 5-year average ended 2019 or the actual expense amount incurred in 2020. In this case, the 5-year average expense of $35,548,000 exceeds the 2020 actual expense amount of $28,786,000.

Therefore, I recommend that the Commission remove $7,511,000 from the Company's forecasted expense of $43,059,000 and approve the 2022 expense amount for the

Operations, Maintenance and Metering program at $35,548,000, plus any inflationary cost adjustment that the Commission wishes to grant, as previously discussed.

Service Restorations – On line 23 of schedule in Exhibit AG-1.48, the Company shows $92,129,000 of expense for this program in 2019, $53,979,000 for the 5-year average, $71,262,000 for 2020 actual, and $74,359,000 for 2022. According to the direct testimony of Ms. Houtz, beginning on page 2, the Company determined the 2022 expense amount based on the average expense amount over the three years from 2018 and 2020, and added labor and other inflation increases for 2021 and 2022. The Company also proposes a service restoration tracker and cost deferral mechanism, which I will discuss later in a separate section of my testimony.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECASTED RESTORATION EXPENSE FOR 2020?

A. In her testimony, Ms. Houtz states that service restoration costs can vary significant from years to year due to weather events. In response to discovery request AG-CE-587, which is included in Exhibit AG-1.49, the Company provided actual costs incurred from 2015 to 2020. During this six-year time-period restoration costs have ranged from $35.5 million to $92.1 million. Even in the most recent three years, from 2018 to 2020, restoration costs have ranged widely from $65.3 million to $92.1 million.

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. To establish a reasonable level of service restoration costs for the projected test year, I used a five-year average of actual expenses from 2016 to 2020. This longer period of time will smooth the volatility in costs that can occur over a shorter period of time. The resulting amount is $60,598,000. Given the variability of restoration costs, the use of a five-year average is a reasonable approach. In the Company's prior rate case No. U-20697 the Commission made a similar point in rejecting the Company's proposed three-year average proposal and approving the test year service restoration expense for the projected test year based on the 5-year average amount.

> The Commission agrees with the ALJ that Consumers' storm restoration projection should be based on a five-year average. Consumers' argument that a three-year average captures unusually high restoration costs in recent years is precisely the reason that the Commission prefers a five-year average: a five-year average, in this case, tends to provide a more accurate projection because it flattens, but does not eliminate, the effects of unusually high cost years due to a cycle of damaging weather (and would also have the reverse effect for unusually low-cost years).[100]

In its recent rate case No. U-20561, DTE Electric proposed a five-year average 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 $74,359,000 million based on a three-year average of actual costs from 2018 to 2020, with 2020 being a forecasted amount. 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. In her direct testimony, Ms. Houtz

[100] MPSC Case No. U-20697, December 17, 2020 order, at page 176.

attempts to support her three-year average approach by presenting information for a relatively short time-period. This limited time-period distorts the reality about the frequency and severity of storms over the past decade. For example, in Figure 4 on page 6 of her direct testimony, she shows the number of Major Event Days (MEDs) on a rising slope from 2015 to 2020. In reality, with the exception of 2016, the number of MEDs in 2020 was the same as 2017 and within one event of 2018 and 2019.

Therefore, the Company's justification to use a three-year average to forecast restoration costs for the projected test year is not based on any clear evidence of increases in storm activities and should not be accepted by the Commission.

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 2019. 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. In response to discovery, the Company reported that it utilized at least 883 employees in Storm Pre-Staging activities in 2020 and forecasts that it will exceed 2,300 employees in

2021 and 2022, plus 2,500 outside contractors.[101] It is not clear how much more value is being derived from the massive increase in people added to pre-staging activities.

Ms. Houtz claims that the expanded ICS has already proven successful in 2019. Based on the information provided in response to discovery request AG-CE-870, which is included in Exhibit AG-1.50, the increased performance based on only one single event is only marginal and certainly does not justify the increased expense. It also does not provide a comparison to the level of performance achieved from other similar events in prior years. Therefore, the jury is still out whether the increased expense to establish a larger ICS and pre-staging workforce is paying off.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S SERVICE RESTORATION O&M EXPENSE FORECAST?

A. The Company's forecasted expense for service restorations is based on a short three-year period and does not take into consideration the variability that can occur with these costs over multiple years. Therefore, a longer time period, as approved by the Commission in Case No. U-20162, is advisable and preferred. Based on a 5-year average of actual costs incurred by the Company from 2016 to 2020, the expense amount for service restorations should be set at $60,598,000 for 2022.

[101] Exhibit AG-1.50 includes DR AG-CE-869.

Therefore, I recommend that the Commission remove $13,761,000 from the Company's forecasted expense of $74,359,000 and approve the 2022 expense amount of $60,598,000, plus any inflationary cost adjustment that the Commission wishes to grant, as previously discussed.

<u>Field Operations</u> – On line 31 of schedule in Exhibit AG-1.48, the Company shows $22,224,000 of expense for this program in 2019, $21,579,000 for the 5-year average, $18,207,000 for 2020 actual, and $28,797,000 for 2022. The 2022 forecasted expense is an increase of $10.6 million over the 2020 actual expense, or a 58% increase, and $7.2 million increase over the 5-year average, or an increase of 33%. From pages 288 to 292 of his direct testimony, Mr. Blumenstock discusses this program and the sub-programs within the larger program. In the four pages of testimony, Mr. Blumenstock does not provide sufficient specific information to support the increases in the sub-programs, other than for the Grid Management sub-program. It would be reasonable to expect the Company to provide substantial references to specific increases in work units or work activities with related dollar amounts and explanations of why those activities are increasing to justify the large increases in expense at the sub-program level or at the overall program level. Without this detailed support and justification, it is not possible to determine whether the forecasted expenses are reasonable and should be approved. The only exception is the Grid Management sub-program on line 30 of the exhibit. With regard to this sub-program, on page 292 of his testimony, Mr. Blumenstock identifies three specific items that justify $1.1 million.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S FIELD OPERATIONS O&M EXPENSE FORECAST?

A. The Company's forecasted expense for the Operations, Maintenance and Metering program for 2022 is not adequately supported. As a result of the limited information provided by the Company, the only reliable basis for the 2022 expense forecast is to use the most recent actual expense. In this regard, I propose to use the highest expense amount between the 5-year average ended 2019 or the actual expense amount incurred in 2020. In this case, the 5-year average expense of $21,579,000 exceeds the 2020 actual expense amount of $18,207,000. To the 5-year average amount of $21,579,000 I added the $1,100,000 of identified Grid Management expenses to establish a reasonable forecasted expense of $22,679,000 for 2022.

Therefore, I recommend that the Commission remove $6,118,000 from the Company's forecasted expense of $28,797,000 and approve the 2022 expense amount of $22,679,000 for the Operations, Maintenance and Metering program, plus any inflationary cost adjustment that the Commission wishes to grant, as previously discussed.

<u>Electric Planning</u> – On line 53 of schedule in Exhibit AG-1.48, the Company shows $9,593,000 of expense for this program in 2019, $8,800,000 for the 5-year average, $9,579,000 for 2020 actual, and $13,748,000 for 2022. The 2022 forecasted expense is an increase of $4.2 million over the 2020 actual expense, or a 44% increase, and $4.9 million increase over the 5-year average, or an increase of 56%. Beginning on page 297 of his direct testimony, Mr. Blumenstock discusses this program and the sub-programs within the larger program. In the three pages of testimony, Mr. Blumenstock does not provide sufficient specific information to support the increases in the sub-programs, other than for the HVD System Planning sub-program. As stated earlier with regard to other programs and sub-programs, Mr. Blumenstock's testimony is devoid of specific data, such as work units or work activities with related dollar amounts and explanations of why those activities are increasing to justify the large increases in expense at the sub-program level or at the overall program level. Without this detailed support and justification, it is not possible to determine whether the forecasted expenses are reasonable and should be approved. The only exception is in the HVD System Planning sub-program on line 50 of the exhibit. With regard to this sub-program, on page 298 of his testimony, Mr. Blumenstock identifies an incremental expense item of $843,000 that is supported.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S ELECTRIC PLANNING O&M EXPENSE FORECAST?

A. The Company's forecasted expense for the Electric Planning program for 2022 is not adequately supported. As a result of the limited information provided by the Company, the only reliable basis for the 2022 expense forecast is to use the most recent actual expense. In this regard, I propose to use the highest expense amount between the 5-year average ended 2019 or the actual expense amount incurred in 2020. In this case, the 2020 actual expense of $9,579,000 exceeds the 5-year average expense amount of $8,800,000. To the 2020 amount of $9,579,000 I added the $843,000 of identified HVD System

Planning expense for the second helicopter patrol to establish a reasonable forecasted expense of $$10,422,000 for 2022.

Therefore, I recommend that the Commission remove $3,326,000 from the Company's forecasted expense of $13,748,000 and approve the 2022 expense amount of $10,422,000 for the Electric Planning program, plus any inflationary cost adjustment that the Commission wishes to grant, as previously discussed.

Q. WHAT IS TOTAL DISALLOWANCE FOR DISTRIBUTION OPERATIONS O&M EXPENSE THAT YOU PROPOSE FOR THE 2022 PROJECT TEST YEAR?

A. I recommend that in total, the Commission disallow $34,503,000 from the Company's forecasted O&M expense of $185,039,000 for the 2022 projected test year.

D. Line Clearing Expense

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

A. As shown on line 21 of Exhibit A-53 (PLB-1), the Company proposes to increase the expense for line clearing from the $53,289,931 spent in 2019 to $94,355,000 for the projected test year. The forecasted amount for the projected test year an increase of 77% over the 2019 amount. According to the exhibit and the direct testimony of Pamela

Bolden, nearly all of the increase is for clearing the Company's Low Voltage Distribution lines. Vegetation expenses for LVD lines are projected to increase from $42.0 million in 2019 to $81.5 million in 2022, which is a 94% increase. On page 7 of her direct testimony, Ms. Bolden states that the Company's objective is to achieve a 7-year clearing cycle by 2025. In 2020, the Company was at approximately a 13-year clearing cycle.[102]

Q. WHAT CONCERNS DO YOU HAVE WITH THE COMPANY'S LINE CLEARING PROPOSAL?

A. I have two major concerns. First, on line 27 of Exhibit A-53, the Company shows that the cost for clearing LVD lines per mile is increasing from $11,677 per mile in 2019 and $10,989 in 2020 to approximately $13,676 per mile in 2022. The higher amount in 2022 reflects an average rate of increase of approximately 12% per year from 2020. This is in comparison to the annual rate of increase in the CPI of approximately 2.0% over the same timeframe, as forecasted by IHS Markit.[103] In addition to forecasting internal wage increases of 3.2%, the Company stated that in late 2020 and 2021 it added new smaller Michigan-based contractors at billing rates that are 17% higher than other contractors. The discovery response also stated that some of the new crews are less productive starting out.[104] The business practice of granting work at rates that are higher than competitive work rates raise concerns about the Company paying higher rates to support commercial

[102] Exhibit A-53, line 31 (7 year 2025 target ÷ 0.54 in 2020) = 13 years.
[103] CECo response to DR AG-CE-591.
[104] Exhibit AG-1.51 includes DR AG-853

businesses on the back of utility customers who end up paying the higher costs that the Company seeks to recover in rates.

Second, line 2 of Exhibit A-54 (PLB-2) shows that under its tree clearing plan, the Company expects to increase the annual spending program from $53.3 million in 2019 to $120.3 million in 2025 to achieve the 7-year clearing cycle. This is an increase in spending of 126% over the seven-year period. In contrast, on lines 3 to 5, the Company shows that by 2025, it expects to reduce tree-related outage events by 25.4% from 10,682 outages in the 2019 to 2020 period to 7,959 outages in 2025, or a reduction of 2,723 outages.

When dividing the $67.0 million increase in spending between 2019 and 2025 by the number of avoided outages of 2,723, the result is a cost per avoided outage of $24,605. This seems to be a high cost per avoided outage. In response to discovery, the Company stated that it was not underestimating its forecast of avoided outages in Exhibit A-54 and pointed out that for each outage event on average 101.5 customers are affected.[105] This means that by the end of 2025, approximately 276,275 customer outages could be prevented from the additional spending of $67 million. In her workpaper WP-PLB-3, Ms. Bolden shows that 1,161,651 customers were interrupted by tree caused outages in 2019. Therefore, the 276,725 prevented customer outages would be a 24% reduction. In contrast with the 126% increase in spending, the increased spending does not appear to be a sound economic trade-off of cost versus benefit.

[105] *Id*. Includes DR AG-852.

Although in the discovery response AG-CE-852 included in Exhibit AG-1.51 the Company performs a calculation to show that customer savings from prevented power outages would exceed the cost of prevent the outages, the calculation relies on a cost of $228 per outage incurred by a customer. No source or basis for that cost was provided and it has not been validated. Similar data provided in the past and attributed to the Lawrence Berkeley National Laboratory have been overstated and unreliable.

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

A. Although I have a high degree of skepticism that the Company will achieve the target reduction in tree-related outages with the proposed increased spending from 2021 to 2025, I recommend that the Commission allow the Company to complete the forecasted number of miles of HVD and LVD line clearing at an appropriate cost per mile. As stated earlier, due to the forecasted increase in employee wages and contractor rates, the Company's forecasted cost per mile is not appropriate.

Furthermore, on page 22 of her direct testimony, Ms. Bolden stated that the personal contact restrictions imposed by the COVID-19 pandemic forced the Company to find more cost-effective ways to resolve customer calls about tree-down problems by dispatching fewer crews or no work crews at all for certain situations and resolving the problem over the telephone. This change reduced the cost per mile for tree clearing by nearly 14%.[106] Although some customers may prefer a site visit, which in the past probably was not needed in the first place, there is no reason why this practice cannot continue into 2021 and future years

Because of these issues, I decided to use the actual 2020 cost per mile for HVD and LVD line clearing and applied that cost to the miles forecasted by the Company to be cleared in order to arrive at the forecasted expense of $74,834,000 for 2022.[107] This amount was calculated by multiplying the HVD cost per mile of $8,217 by the 1,131 miles of HVD lines forecasted by CECo to arrive at the HVD forecasted expense of $9,293,000. For the LVD line clearing expense, I multiplied the 2020 actual cost per mile of $10,949 by the 5,986 miles forecasted by the Company to arrive at the forecasted amount of $65,541,000. The total of these two amounts is $74,834,000.

Based on these calculations, I recommend that the Commission remove the difference of $19,521,000 between the Company's forecasted amount of $94,355,000 and the $74,834,000 from the Company's forecasted O&M expense for line clearing.

E. Power Generation Expense

Q. THE COMPANY PROPOSED $156.7 MILLION OF O&M EXPENSE FOR THE POWER GENERATION AREA FOR THE PROJECTED TEST YEAR. WHAT

[106] Pamela Bolden direct testimony on page 22, Figure 10: ($10,924 – $12,665) ÷ $12,665 = 14%.
[107] Exhibit AG-1.51 includes DR AG-CE-853 Attachment 1. Refer to lines 26 and 27, column (k).

ADJUSTMENTS DO YOU RECOMMEND TO THIS FORECASTED EXPENSE AMOUNT?

A. Line 6 on page 1 of Exhibit A-95 (SAH-5) shows total O&M expense for the Power Generation area increasing from $133.0 million in 2019 to $156.7 million for the projected 2022 test year. The majority of the increase is in base O&M expense and Major Maintenance expense.

With regard to base O&M expense, beginning on page 114 of his direct testimony, Mr. Hugo discusses some unusual credits and other one-time special items that reduced the 2019 expense and distorts the comparison in expense from that year to 2022. To avoid those distortions, in discovery the Company was asked to provide the actual O&M expense for 2020 for a more recent and better comparison to the forecasted amount for 2022. In response to discovery, the Company reported that for 2020 Base O&M expense was $106,821,000.[108] This amount is $12,500,000 lower than the Company's 2022 forecasted amount of $119,321,000. Other than a $1,488,000 expense increase attributed to new solar resources and $6,888,000 for inflationary cost increases calculated by the Company, there are no other explanations in Mr. Hugo's testimony that justify the remaining increase of $4,124,000 from 2020 to 2022.

For purposes of calculating a Base O&M expense for 2022, I used the 2020 actual expense of $106,821,000 as the most recent actual expense plus the $1,488,000 forecasted by the

[108] Exhibit AG-1.52 includes DR AG-CE-781 with attachments.

Company for solar projects to arrive at an adjusted base of $108,309,000. This amount is $11,012,000 lower than the Company's forecasted Base O&M expense of $119,321,000.

I recommend that the Commission remove the difference of $11,012,000 from the Company's forecast and set the 2022 forecasted base O&M expense at 108,309,000 plus any inflationary cost increase it may want to grant, as discussed in my testimony above.

F. Customer Experience & Operations Expense

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED EXPENSE FOR THE PROJECTED TEST YEAR FOR THE CUSTOMER EXPERIENCE AND OPERATIONS AREA.

A. Line 4 on page 1 of Exhibit A-87 (AJG-2) shows total O&M expense in the Customer Experience and Operations area increasing from $58.8 million in 2019 to $95.2 million for the projected 2022 test year. The increase is reflected in all of the three sub-areas, including Customer Interactions. As shown on page 2 of the exhibit, Customer interactions consists of five functions. Based on my review, I will propose certain adjustments to the Digital Customer Operations and Analytics & Outreach functions.

With regard to the Analytics and Outreach function, the Company incurred $1,404,000 of expense in this area in 2019. As shown on line 5 of page 3 of Exhibit A-87, for 2022 the Company is forecasting only $709,000. However, in response to discovery, the Company disclosed that in 2022 the Company will be charging other operations within the Company for the use of the resources available within the Analytics and Outreach function.[109] In other words, the Company has decided to disperse the cost among various other areas.

On page 23 of her testimony, Ms. Griffin explain that the Analytics and Outreach function consists of three categories: Customer Research, Customer Data and Analytics and Customer Outreach. Customer Research involves data collection and analysis from industry sources to offer new service options in order to improve the customer experience. No details were provided about what has been accomplished in this area and of what real value it has been to customers.

According to Ms. Griffin, Customer Data and Analysis is focused on better understanding the Company's customers among other general objectives. The only example that Ms. Griffin could provide in her testimony was the development of a Financial Health Analytics tool that gauged the distress level of customers during the COVID-19 pandemic. Supposedly, with this tool, the Company was able to target programs and plans to help customers during 2020. No details were provided about how effective this tool was and how many customers were helped and with what. No description was provided about the Customer Outreach work area in Ms. Griffin's direct testimony.

In discovery, the Company was asked to identify the number of employees and contractors working in the Analytics and Outreach area for each year from 2019 to 2022. The response to discovery response AG-CE-954, included in Exhibit AG-1.53, shows that 18 employees

[109] Exhibit AG-1.53 includes DR AG-CE-954.

and 5.5 contractors worked in this area in 2019. By 2022, the number will mushroom to 46 employees and 7 contractors. As shown in the discovery response, these employees and contractors supposedly will be doing customer research, customer data collection and analytics, work on marketing strategy (22 out of the 46 employees and 1 contractor) plus supervision and management.

Q. WHAT IS YOUR ASSESSMENT OF THE ANALYTICS AND OUTREACH FUNCTION AND THE O&M EXPENSE FORECASTED FOR 2022?

A. The Company has not provided any substantiative evidence that the Analytics and Outreach function is creating value for customers sufficient to justify the $1.4 million expense in 2019 and probably much more forecasted for 2022. It is not clear what the ultimate objective of the research and customer outreach really is. If it is revenue growth, then it should be clearly articulated and defined. If it is increasing customer satisfaction, then this objective should also be clearly defined and justified versus the cost to achieve the goal, so that the Commission can make a determination if the incremental improvement is justified by the cost to achieve it. Currently, there is no stated objective or justification for the expense.

Therefore, I recommend that the Commission remove at least $1.4 million of expense equivalent to the amount shown in 2019, which is the historical expense before a portion of the expense was allocated to other areas of the Company. Unfortunately, the Company did not disclose the total forecasted expense amount for 2022 to be incurred in this area before the allocation of a portion of the expense to other areas of the Company. However, based on the increase in the number of employees and contractors between 2019 and 2022. it is likely that this expense has at least doubled to more than $2.8 million. I recommend that the Commission order the Company that in future rate cases it should identify the total expense for Analysis and Outreach before any splitting, billing or allocation to other areas of the Company in order to facilitate the analysis and assessment of this expense item.

Q. ARE THERE OTHER EXPENSE ITEMS THAT YOU PROPOSE SHOULD BE ADJUSTED WITHIN THE CUSTOMER EXPERIENCE AND OPERATIONS AREA?

A. Yes. As discussed in the Capital Expenditures section of my testimony under Information Technology Projects, there are four IT systems that fall within the Customer Experience and Operations area of responsibility where in addition to the disallowance of capital expenditures I also recommend the disallowance of the related O&M expense. They are:

1. CRM system - O&M expense of $1,441,000
2. C&I Account Management system - O&M expense of $1,206,000
3. Bill Redesign and Delivery Transformation project – O&M expense of $1,600,000
4. Customer Loyalty and Alternative Payment Methods projects - $2,200,000

The total amount of proposed O&M expense disallowance is $6,447,000. The reasons for the proposed disallowance of these expense items were discussed in the Capital

Expenditures section of my testimony and is not e repeated here. I reiterate my recommendation that the Commission should remove the expense amount of $6,441,000 from the Company's total forecasted O&M expense for the projected test year.

Therefore, for the Customer Experience and Operations area, I proposed a total disallowance of O&M expense of $7,841,000.

G. Uncollectible Accounts Expense

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

A. On line 10 of page 2 of Exhibit A-85 (KMG-4), the Company proposed $17,079,000 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 2017 to 2019.

In discovery the Company was asked to provide updated information for the three-years 2018 to 2020. Based on the information provided in the response to discovery request MEC-CE-403a, which is included in Exhibit AG-1.54, I have recalculated the forecasted expense at $14,191,000 for the projected test year. Exhibit AG-1.54 shows the calculation. The difference is $2,888,000 from the Company's forecast.

The 2018 to 2020 information is more recent data and therefore is preferred over the information used by the Company. Therefore, I recommend that the Commission remove

$2,888,000 from the Company forecasted uncollectible accounts expense for the projected test year.

H. Corporate Expenses

Q. DO YOU PROPOSE ANY ADJUSTMENTS TO CORPORATE EXPENSE?

A. Yes. On line 1 of Exhibit A-82 (KMG-1), the Company shows Corporate O&M expense increasing from $51.1 million in 2019 to a forecasted level of $62.7 million in the projected test year. In addition to inflationary cost increases calculated by the Company, there are other items that are increasing the total expense amount for the projected test year. Some relate to employee development programs and others to insurance costs and IT projects sponsored by the Corporate Services function. In my testimony below, I will discuss certain adjustments in those programs and cost areas.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECASTED O&M EXPENSE FOR EMPLOYEE DEVELOPMENT?

A. Beginning on page 10 of her direct testimony, Ms. Gaston discusses two employee development plans and the related expense for 2022 to pursue those programs. With regard to the Career and Reward Framework project, the Company has proposed an O&M expense amount of $544,000 to hire an industry expert to "…implement a framework to create a seamless experience from hiring process through career development." Although this statement is a bit cryptic, it appears that what the Company aims to achieve is to develop career paths for employees. Aside from all the cliches and buzzwords included in the description of this project, it seems odd that the Company needs to hire a consultant to develop career tracks for employees under the Corporate function when the Company has or should have Human Resources professionals proficient in developing career tracks for employees and guiding them through this process.

The hiring of a consultant to perform a task that should be done by the Company's HR department seems costly and unnecessary. I recommend that the Commission disallow this proposed expense amount of $544,000.

With regard to the Co-worker Development project, the Company has forecasted $1,005,760 of expense to expand the current leadership training program and apparently retrain employees to support the Company's [new] Electric strategy. From the description, and sifting through lots of buzzwords and jargon, it is not clear what the leadership program is being expanded to accomplish and why co-workers need retraining. The "Co-worker" designation in the title of the program is also somewhat odd. It is not clear what type of employees are covered under the "Co-worker" title.

The Company has not adequately defined and justified spending $1,005,760 in 2022 on this project. Therefore, I recommend that the Commission remove this amount from the Company's forecasted expense for the projected test year.

Q. ARE THERE CERTAIN EXPENSE ITEMS RELATED TO CORPORATE IT PROJECTS THAT SHOULD BE REMOVED FROM THE PROJECTED YEAR O&M EXPENSE?

A. Yes. As discussed in the Capital Expenditures section of my testimony under Information Technology Projects, there are two IT systems that fall within the Corporate Services area of responsibility where in addition to the disallowance of capital expenditures I also recommend the disallowance of the related O&M expense. They are:

1. Business Planning Optimization project - O&M expense of $330,000
2. Integrated Business Planning and Management Reporting system - O&M expense of $335,000

The total amount of proposed O&M expense disallowance is $665,000. The reason for the proposed disallowance of these expense items were discussed in the Capital Expenditures section of my testimony and will not be repeated here. I reiterate my recommendation that the Commission should remove the expense amount of $665,000 from the Company's total forecasted O&M expense for the projected test year.

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

A. On page 3 of his direct testimony, Mr. Tim Underwood shows a table with the net insurance expense for each year from 2019 to 2022 consisting of the insurance premium expense and the reduction of expense from premium refunds and insurance reserve distributions. The Company recorded net insurance expense of $9.1 million in 2019 and has forecasted $13.8 million for the 2022 project test year.[110] I will analyze the two major components that make up the net insurance expense separately. I will point out that although Mr. Underwood performs the insurance calculations the net impact on O&M expense for the projected test year are reflected on line 3 of Exhibit A-83 (KMG-2), and specifically in column (m), which is sponsored by witness Gaston. Ms. Gaston addresses the insurance adjustments on page 9 of her direct testimony.

With regard to the insurance premium expense charged to O&M expense for the electric business, Mr. Underwood sponsored Exhibit A-113 (DTU-1) showing a buildup of insurance premium expense from 2019 to 2022. Although this exhibit is a bit confusing and hard to follow, there are two major factors that impact the forecasted insurance expense for 2022 as calculated by Mr. Underwood. One is the use of escalations factors and the other is the addition of wind generation projects that increase insurance premiums from 2020 to 2022.

The primary reason for the increase in the insurance expense from 2019 to 2022 is Mr. Underwood's use of arbitrary insurance premium escalation factors ranging from 5% to 25% per year. Asked in discovery to provide the source of the escalation factors, his response was a reference back to page 4, lines 12-18, of his direct testimony.[111] In this

[110] The table on page 3 of Mr. Underwood's direct testimony shows $14.8 million of net insurance expense for 2022. However, this amount appears to be incorrect and should be $13.8 million. The Distributions reduction of $4.9 million in 2022 should be $5.9 million, as calculated and shown on page 9 of Ms. Gaston's direct testimony.
[111] Exhibit AG-1.55 includes DR AG-CE-856.

section of his testimony, Mr. Underwood states that the escalation rate applied to each premium was based upon his judgement, experience and knowledge of the insurance industry.

In other words, he simply guess-estimated the rates of increase. In his testimony, he also references certain articles in Exhibit A-114. However, those articles are very general thoughts and vague opinions, and provide no specific guidance about percentage increases. The best indication of the direction of insurance premiums is the trend during the most recent three years from 2018 to 2020.

In response to discovery, the Company provided the actual insurance premium expense from 2016 to 2020. The most recent three years show that insurance premium expense has declined from $17.5 million in 2018 to $15.7 million in 2020.[112] This is an indication that the premium escalation rates applied by Mr. Underwood in 2020, 2021 and 2022 are not realistic and should be dismissed.

The second factor that will affect the insurance expense from 2020 to 2022 are the premiums related to three wind generation projects that become operational during that timeframe. In response to discovery, Mr. Underwood provide additional details on the assumptions used to calculate the 2022 expense. The schedules provided show the Gratiot wind project adding $225,000 in insurance premiums in December 2020, the Crescent

[112] *Id*. Includes DR AG-CE-864.

wind park adding $225,000 of insurance premiums in February 2021, and the Hartland wind park adding an additional $300,000 in December 2021.[113]

Q. HAVE YOU MADE A DETERMINATION OF WHAT THE INSURANCE EXPENSE SHOULD BE WITHOUT THE ESCALATION FACTORS USED BY MR. UNDERWOOD?

A. Yes. In Exhibit AG-1.56, I have calculated the insurance expense forecast of $17,114,000 for 2022 before the reduction for insurance refunds and distributions. To arrive at this amount, I started with actual amount of insurance expense reported by the Company for 2020 and the insurance premium for the Gratiot wind project. I then applied a 2% inflation rate to the prior year total to arrive at an adjusted 2021 insurance expense and repeated the process to add the additional insurance premiums for the other two wind parks, including another year of inflation cost adjustment. The end result is a forecasted premium expense for 2022 of $17,114,000. In comparison to the Company's calculation of $19,732,000, my calculation is approximately $2.6 million lower.

With regard to the insurance refunds and distributions credited to insurance premium expense, the Company calculated an average amount of $5,892,300 over the five years ended 2019. In response to discovery request AG-CE-864, included in Exhibit AG-1.55,

[113] Id. Includes DR AG-CE-859.

the Company reported the total amount of insurance refunds/distributions of $13,861,120 received in 2020.

Given the availability of this more recent amount, in Exhibit AG-1.56, I used the five-year average of the premium refunds/distributions received from 2016 to 2020. The five-year average over the more recent period is $7,897,000. After deducting this amount from the $17,114,000 of insurance premium expense previously calculated, the net amount of forecasted insurance expense for 2022 is $9,217,000.

The amount of net insurance expense of $13,800,000 forecasted by the Company for 2022 is excessive and based on unsupported premium increase assumptions. Therefore, I recommend that the Commission adopt my forecast of $9,217,000 and remove $4,583,000 from the Company's O&M forecast for the projected test year.

I. Information Technology Expense

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

A. On line 12 of page 1 of Exhibit A-107 (JDT-5), the Company shows $10.8 million of expense for 2019 with the expense level increasing to $20.5 million in the projected test year. The $9.7 million increase in expense represents a 90% increase over the 2019 cost level and seems excessive.

In response to discovery, the Company provided the O&M expense for the five years from 2016 to 2020. 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 $12.0 million annually.[114] For 2019, the Company incurred $10.8 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 but the actual expense turned out approximately $3.0 million less. Similarly, in Case No. U-20697, the Company had forecasted $17.0 million for 2020 and now shows a forecast of $8.4 million, which is a 51% reduction.[115] There is a pattern developing here of the Company overestimating the IT-Investment O&M expense for future years.

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

A. Company witness Christopher Varvatos in direct testimony in Case U-20650 best describes what IT Investment expense entails. 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.[116] Beginning

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[114] Exhibit AG-1.57 includes CECo response to DR AG-CE-672 Attachment.
[115] *Id*. included DR AG-CE-821.
[116] Christopher Varvatos in Case U-20650 direct testimony at page 19.

on page 32 of his direct testimony in this current case, Mr. Tolonen provides a similar explanation in summary form.

Given the link between new project planning and development and new projects funded by capital expenditures, 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. At the bottom of page 1 of Exhibit A-12 (JDT-6), Schedule B-5.3, the Company shows that capital expenditures in 2022 are forecasted to increase to $77.2 million, or 47%, from the $52.5 million spent in 2019. When I apply this rate of growth to the actual O&M expense for 2019, I calculate a forecasted expense amount of $15,929,000 for 2022.[117] This amount is $4,567,000 lower than the O&M expense of $20,496,000 forecasted by the Company for the projected test year.

The Company's forecasted O&M expense of $20,496,000 for IT Investments expense is excessive and unreasonable. Therefore, I recommend that the Commission remove the amount of $4,567,000 from the Company's forecasted O&M expense.

Q. ARE THERE CERTAIN EXPENSE ITEMS RELATED TO CORPORATE IT PROJECTS THAT SHOULD BE REMOVED FROM THE PROJECTED YEAR O&M EXPENSE?

A. Yes. As discussed in the Capital Expenditures section of my testimony under Information Technology Projects, there is one IT system project that falls within the IT area of

[117] 2019 expense amount of $10,836,000 x 1.47= $15,929,000.

responsibility where in addition to the disallowance of capital expenditures I also recommend the disallowance of the related O&M expense. This is the Digital-Hybrid Cloud and Data Center Migration project, where I recommended that the $1,535,000 of O&M expense related to this project also be disallowed.

The reasons for the proposed disallowance of this expense item were discussed in the Capital Expenditures section of my testimony and will not be repeated here. I reiterate my recommendation that the Commission should remove the expense amount of $1,535,000 from the Company's total forecasted O&M expense for the projected test year.

Q. DO YOU HAVE OTHER CONCERNS WITH INFORMATION TECHNOLOGY COSTS INCURRED BY THE COMPANY?

A. Yes. Cloud computing costs are becoming a larger part of the IT department's operating expense. In response to discovery, the Company disclosed that in 2019, the potion of cloud computing costs allocated to the electric business was approximately $1.3 million. By the end of 2022, the Company has forecasted that these costs will increase to $7.8 million.[118] This amount does not include the portion allocated to the gas business, which would make the amount much larger.

With one of the Company's main IT objectives being the continued migration of more system applications to the cloud, it is nearly certain that these costs will continue to increase in future years. However, it is not clear that the increasing cloud computing costs

[118] Exhibit AG-1.58 includes DR AG-CE-893.

are being offset by lower O&M costs and lower capital expenditures from fewer on-premise data processing operations and hardware purchases. The Company has not provided an overall analysis to support the premise that cloud computing is a net benefit and is currently lowering overall costs or will be reducing cost in the future and to what extent.

Therefore, I recommend that the Commission direct the Company to perform an analysis and present evidence in the next rate case and other future rate cases that shows the net benefits or incremental costs of cloud computing versus diminishing on-premise data processing and hardware purchases.

J. Incentive Compensation Expense

Through the testimony of witnesses Amy Conrad and Michael Stuart, the Company has proposed to recover in rates nearly $5.9 million of short-term incentive compensation.[119] 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 stated by Mr. Stuart in his testimony. I will note here that in response to discovery, the Company stated that it did not make any structural changes to the officer and non-officer incentive compensation plans since filing its prior rate case No. U-20697. However, the Company

[119] Exhibit A-71 (AMC-3).

made certain revisions to the operating performance goals used as a basis to award incentive compensation. I will discuss some of these changes in my testimony below.

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).

The major components of the EICP for non-officer employees are shown in Exhibit A-69 (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 experience/satisfaction, as well as new goals for trash reduction, generation customer value and demand response. To achieve 100% payout of this grouping, the Company needs to only achieve 6 of the 9 operating performance measures, or 67%.

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. Officer and Non-officer employees have received the following percentage payout of the target amount in recent years.[120]

	Overall Short-term Incentive Payout										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Officer	143%	121%	105%	135%	124%	146%	141%	104%	136%	122%	153%
Non-Officer	100%	0%	115%	118%	125%	123%	133%	112%	123%	111%	139%

With the exception of 2011 where no payout to non-officer employees occurred, it is readily apparent from the table above that in the past 11 years there have been consistent payouts above 100%. This record indicates that the performance measures are easily achievable and incentive compensation is not at risk.

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 $5.9 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.

[120] CECo response to DR AG-CE-972.

Q. WHAT IS YOUR ASSESSMENT OF THE PERFORMANCE MEASURES INCLUDED IN THE 2020 EICP?

A. The 2020 performance measures were revamped from the 2019 performance measures. The Company removed Cyber Safety, Customer On-Time Delivery, and Service On-time commitments from the 2019 performance goals and replaced them with an Employee Empowerment Index, Demand Response, and Trash to Landfill goals in 2020. The changes show a trend of fewer customer-related performance goals and more internal administrative goals. I will discuss my concerns with some of these measures and specifically the ease or difficulty in achieving them. The 2020 performance measures are shown in Exhibit A-69 (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 24 of her direct testimony where with respect to 2021 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. 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 2011 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 4 of his testimony that the Company has achieved "… $4.6 million of annual direct savings, and $8.1 million of annual total savings that accrue to the benefit of the customer."

Also, on page 5 of his direct testimony, Mr. Stuart indicates that the Company is saving $8.2 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 in 2018 and 2019 from the prior two years.[121]

In addition, more recent data shows that the Distribution Reliability statistics show an increase in the SAIDI from 161 in 2017 to 235 in 2019 and a decline in 2020 to 195.[122] This is very inconsistent performance. In response to a discovery request, the Company reported that the SAIDI goal has not been met in the last four years.[123] Therefore, this more recent information shows that, despite the incentives of the EICP, certain key measures are moving in the wrong direction.

I will also 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.

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[121] CECo response to DR AG-CE-811
[122] Richard Blumenstock direct testimony at page 32.
[123] CECo response to DR AG-CE-975.

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.

Mr. Stuart also points to potential annual savings of $254 million since 2006 for supposedly keeping O&M expenses below the rate of inflation.[124] 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 $30.6 million of inflationary cost increases reflecting payroll increases of more than 3% and CPI increases for non-labor costs. In fact, O&M expenses in total are projected by the Company to increase by $108.1 million or 18% from 2019 to the end of the 2022 projected test year.[125] 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 in 2020, it is not possible to assess yet what if any real financial benefits will accrue to customers from those new measures.

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[124] Michael Stuart direct testimony at page 6.
[125] Exhibit A-13 (JRC-51), Schedule C-5.

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?

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 2011. 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 $5.9 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-20697, 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-20697. 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 $983,300 for meeting the basic threshold level of performance and shown in the Company's discovery response AG-CE-972, which is included in Exhibit AG-1.59.

K. Employee Benefits Expense

Q. PLEASE DISCUSS YOUR CONCERNS WITH THE COMPANY'S FORECASTED EMPLOYEE BENEFITS EXPENSE FOR THE PROJECTED TEST YEAR.

A. I have three major concerns with the Company's forecasted expense for employee benefits for the projected test year. They pertain to (1) the unsupported increase in expense for the Defined Company Contribution Plan (DCCP) and the 401(k) Employees' Savings Plan (401k Plan), (2) the inclusion of Benefits Department labor costs with employee benefits, and (3) the continuing decline in the expected rate of return for the pension and OPEB plans. I will address each of them separately.

Q. PLEASE DISCUSS THE PROBLEM WITH THE DCCP AND THE 401K PLAN.

A. On line 2 of page 1of Exhibit A-62 (LBC-1), the Company shows that the DCCP expense increases from $8.6 million in 2019 to $12.1 million in 2022. This is an increase of 42% over three years. Similarly, on line 3 of the exhibit, the Company shows the 401k Plan expense increasing from $8.3 million in 2019 to $11.6 million in 2022. This is an increase of 40% also over three years. Beginning on page 12 of her direct testimony, Ms. Lora Christopher discusses the DCCP and the 401k Plan, but provides no detailed information as to how the 2022 test year expense was determined or any specific justification for the increase from the historical year.

In discovery, the Company was asked to provide the calculations in Excel showing how the 2022 forecasted expense for these two items was determined. In response, the Company referred to the workpapers filed along with the exhibits in this case. However, the problem is that those workpapers do not show how the Company calculated the forecasted expense and do not justify the increase from 2019 to 2022.[126] Without this information, the 2022 forecasted expense for the DCCP and 401k Plan cannot be validated and deemed reasonable.

Due to the lack of supporting information from the Company, the only option left is to set the 2022 expense level for the two items at the latest actual amount. For the DCCP, the 2020 actual amount is $9,674,000. This amount is $2,454,000 lower than the Company's forecasted amount for 2022. For the 401k Plan the 2020 actual amount is $8,632,000. This amount is $2,941,000 lower than the Company's 2022 forecasted amount.

Therefore, I recommend that the Commission remove both of these amounts totaling to $5,395,000 from the Company's forecasted O&M expense.

Q. PLEASE DISCUSS THE PROBLEM WITH THE BENEFITS DEPARTMENT LABOR COSTS BEING INCLUDED WITH EMPLOYEE BENEFITS EXPENSE.

A. On line 6 of page 1of Exhibit A-62 (LBC-1), the Company shows that the expense for Other Benefits increases from $1.7 million in 2019 to nearly $3.0 million in 2022. On pages 37 to 39 of her direct testimony, Ms. Christopher does not explain this increase or

[126] Exhibit AG-1.60 includes DR AG-CE-980 and the referenced workpapers.

provide any underlying justification. In response to discovery, the Company reported that beginning in 2020, the Company is including approximately $1.1 million of Benefits Department labor costs in this Employee Benefits category, which grows to $1,140,000 in 2022.[127] There are two problems with the inclusion of this expense item in Other Employee Benefits line. First, Benefits department labor costs to administer employee benefits is not an employee benefit. It is an administrative cost that belongs with other Human Resources expenses and not in Other Employee Benefits.

Second, in the Corporate Services expenses sponsored by Company witness Gaston, Human Resources costs, including benefits administration, are included with Corporate Expenses on line 4 of Exhibit A-83 (KMG-3). Page 5 of Ms. Gaston's direct testimony, and specifically line 13, makes this point clear. If there has been some reclassification of expense between Exhibit A-83 and Exhibit A-62, it is not shown as reduction of historical expense between 2019 and 2022 in Exhibit A-83. Therefore, the result would be a double recovery of this expense item if not excluded from Other Benefits.

I recommend that the Commission remove the $1,140,000 of Benefits Department Labor expense, which was included with Other Benefits.

Q. WHAT IS THE TOTAL AMOUNT OF EMPLOYEE BENEFITS EXPENSE THAT YOU PROPOSE TO DISALLOW?

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[127] *Id*. includes DR AG-CE-794.

A. In total, for the items discussed above, I recommend that the Commission disallow $6,535,000 of Employee Benefits expense from the amount forecasted by the Company in this rate case.

Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LONG-TERM DECLINE IN THE EXPECTED RETURN RATE FORECASTED BY THE COMPANY FOR THE PENSION PLAN AND THE OPEB PLAN.

A. The Expected Return rate is a major component in the calculation of pension and OPEB expense performed by the actuary. A decrease in the forecasted rate over multiple years will increase pension and OPEB expense booked currently by the Company. Conversely, an increase in the Expected Return rate will decrease pension expense. The reason for this impact on pension expense is that if the plan is expected to realize higher returns from investments in stocks, bonds and other securities, it will partially offset future pension and OPEB costs.

Since at least 2015, the Company has gradually lowered the Expected Return rate for the pension plan and the OPEB plan regularly with each filed rate case. The result has been higher pension and OPEB expense than would have been otherwise experienced had the Expected Return rate been held constant or reduced less. Exhibit AG-1.61 shows the pension and OPEB plan statements since 2015 and Exhibit A-83 (LBC-2), pages 1-3, along with Exhibit A-84 (LBC-3) show the same statements through the year 2028. A review of the Expected Return rate in lower section of these schedules shows that in 2015 for the pension plan the Company was using an Expected Return rate of 7.5%. By 2028, the Company is now projecting a return rate of only 5.75%.

Similarly, for the OPEB plan in 2016, the Company was using an Expected Return rate of 7.25% and now by 2028 the Company has projected the rate will decline to 6.00%.

These trends in the Expected Return rates are counter to the actual returns earned by both plans over the past decade. In response to discovery, the Company provided the actual returns earned by both plans from 2009 to 2020.[128] The information shows that over this 12-year period, the pension plan has earned an average return of 10.3%. This is a far cry from the 5.75% projected by the Company. Similarly, for the OPEB plan, which consists of four VEBA plans, the average return over the 12-year period has been 8.4%, which is significantly higher than the 6% forecasted by the Company by 2028.

In discovery, in both this rate case and prior rate cases, the Company was asked to explain the reasons for this protracted decline in the Expected Return rates. The response to discovery request AG-CE-788, included in Exhibit AG-1.62, provides a very general answer with no analysis or specific reasons. This lack of information is perplexing and concerning. The Company has not provided a rational argument why the Expected Return rates continues to decline almost every year and without a defined end point.

[128] Exhibit AG-1.62 includes DR AG-CE-791.

As stated earlier, the declining Expected Return rates have significant implications on the amount of pension and OPEB expense forecasted each year and the amount included in rates. Although financial consultants perform certain analyses and provide recommendations, the Company ultimately decides what the Expected Return rate should be.

While currently the Company is forecasting negative pension and OPEB expense for the projected test year, those negative amounts can turn into large expense increases in future years as the actions taken recently to prefund the pension plan and modifications to the pension and OPEB plans no longer have a positive effect.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission direct the Company to present in the next rate case a thorough analysis and justification of the decline in the Expected Return rates for both the pension and OPEB plans from 2015 to 2028 with appropriate supporting data and with consideration of recent actual returns achieved by the plans.

L. 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)
Inflationary Cost Adjustments	$ 7.8
Electric Distribution	34.5
Line Clearing	19.5
Power Generation	11.0
Customer Experience & Operations	7.9
Uncollectible Accounts Expense	2.9
Corporate Expenses	6.8
Information Technology	6.1
Incentive Compensation	5.9
Employee Benfits	6.5
Total	$ 101.1

As such, I recommend that the Commission reduce the amount of total O&M costs proposed by the Company by $101.1 million and reduce the revenue deficiency accordingly. Exhibit AG-1.46 provides further details.

VII. 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 13 of Ms. Houtz's direct testimony and page 23 of the direct testimony of Ms. Gaston, the Company proposes to defer service restoration costs above a certain threshold and recover them in a subsequent rate case. Ms. Houtz proposes to establish a service restoration expense amount of $74 million in the revenue requirement in this rate case and to establish an accounting deferral mechanism for any service restoration expense incurred above $84 million. According to Ms. Houtz's testimony, the Company would refund to customers any differences between $74 million and a lower amount incurred by the Company in a future year.

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 $74 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 in 2019. Although 2019 was an unusual year with service restoration expense reaching $92 million, service restoration costs declined to $71 million in 2020. Exhibit AG-1.49 includes this information provided by the Company in response to discovery.

Therefore, the $74 million expense level and the $84 million threshold levels are set significantly above typical average expense levels. Although Ms. Houtz's testimony mentions refunding to customers underspent amounts below the amount of restoration expense set in rates as part of this mechanism, Ms. Gaston's testimony, which should provide more details, is silent on this matter. Ms. Gaston's testimony focuses on how the Company would be able to defer and recover any excess restoration costs over future years.

As stated earlier in the O&M section of my testimony, the Commission has set the service restoration expense in rates for DTE Electric based on a five-year average with no deferral or cost recovery mechanism and that approach seems to have worked well for DTE who operates in adjacent areas to the Company's service area in the State of Michigan.

Therefore, I recommend that the Commission reject the Company's proposal.

VIII. Adjustments To Revenue Deficiency

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

A. Exhibit AG-1.63 summarizes the adjustments to rate base and operating income. The net result is a revenue sufficiency or excess of $30.7 million, which is a reduction of $255.8 million from the Company's requested level of $225.1 million.

I recommend the Commission adopt my proposed adjustments and issue an order granting no rate relief to the Company.

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, 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.

As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, he has been intricately involved in

Experience and Qualifications of Sebastian Coppola

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.

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

As accounting manager and later financial executive for two regulated gas utilities, he has been intricately involved in construction materials procurement, gas purchase strategies and CGR reconciliation cases. He has had direct responsibility

Experience and Qualifications
of Sebastian Coppola

for preparing GCR reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the Michigan Public Service Commission (MPSC). He is intricately familiar with construction projects, the power supply and gas cost recovery mechanisms, gas supply and pricing issues, and regulatory issues faced by utilities.

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

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

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

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

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in (CECo 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.

**Experience and Qualifications
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- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.

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of Sebastian Coppola

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

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric (DTEE) 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue,

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of Sebastian Coppola

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

- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.

Experience and Qualifications
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- 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.

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- o Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- o 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.
- o Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- o Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- o 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.
- o Filed testimony on behalf of the Michigan Attorney General in CECo 2016-2017 GCR Plan case U-17943.
- o Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR Plan case U-17918.
- o Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan reconciliation case U-17334-R.
- o Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- o Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- o 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..
- o Filed testimony on behalf of the Michigan Attorney General in CECo Gas Choice and End-User Transportation tariff changes case U-17900.

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- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.

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- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.
- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CECo's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CECo's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.

Experience and Qualifications of Sebastian Coppola

- Filed testimony in MichCon's 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors' compensation in the 2012 Avista general rate case.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio's power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation's 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo's electric business Pilot Revenue Decoupling Mechanism in case U-16566.

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- 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

U20963-SA-CE-294
Requested By: Lauren Fromm (LF-6)
Respondent: Jason R. Coker
Date of Response: May 4, 2021
Page **1** of **2**

Question:

The following question pertains to a discovery response from Jason R. Coker:

3. Discovery Response U20963-AB-CE-155-Coker_ATT_1 was provided in response to a discovery request from ABATE asking for the amount of contingency included in the bridge period and test year for each project included in Consumers' Projected Capital Expenditures Summary Exhibit No. A-12 (JRC-36), Schedule B-5. Please answer the following questions:

a. Exhibit A-79 (CTF-1) includes contingency in the amount of $4,626,449 in 2021 and $13,471,350 in 2022 combined for the Solar – 2019 Bid Event and the Solar – 2020 Bid Event. Please explain why this is missing from what was provided in U2096-AB-CE-155-Coker_Att_1.

b. Discovery Response U20963-AB-CE-155-Coker_ATT_1 includes contingency for projects included in Exhibit A-12 (SAH-3). The total amount of contingency listed on this response is $8.577 million for the 2021 bridge year and $18.689 million for the test year. However, page 4 of Exhibit A-12 (SAH-3), which Company witness Scott A. Hugo explains on page 33 of his direct testimony is a summary of pages 2 and 3 which are the Generation capital expenditures, lists total contingency expenditures of $6.209 million for the 2021 bridge year and $16.059 million in the 2022 test year. Additionally, pages 8 and 9 of Exhibit A-12 (SAH-3) provide contingency totals for projects greater than $1 million (from pages 1-5 of the same exhibit) that are $7.760 million and $17.998 million. The table below summarizes the 3 contingency figures the Company has provided:

Generation Contingency Expenditures ($000)

	U20963-AB-CE-155-Coker_ATT_1	Exhibit A-12 (SAH-3) p 4	Exhibit A-12 (SAH-3) p 8&9 (projects over $1M)
2021 Bridge Year	$ 8,577.00	$ 6,209.00	$ 7,760.00
2022 Test Year	$ 18,689.00	$ 16,059.00	$ 17,998.00

Please explain why the discrepancy exists between U20963-AB-CE-155-Coker_ATT_1 and Exhibit A-12 (SAH-3) page 4. If either is an error please explain which is correct and update the other to reflect the correct figures.
Please also explain why the contingency totals on pages 8 and 9 of Exhibit A-12 (SAH-3) are greater than those provided on page 4 of the same exhibit when pages 8 and 9 provide figures for projects over $1 million and page 4 provides figures for all projects.

U20963-SA-CE-294
Requested By: Lauren Fromm (LF-6)
Respondent: Jason R. Coker
Date of Response: May 4, 2021
Page **2** of **2**

Response:

a. Contingency in the amount of $4,626,449 in 2021 and $13,471,350 in 2022 for the Solar – 2019 Bid Event and the Solar – 2020 Bid Event are included in the response to U20963-AB-CE-155-Coker_Att_1 on rows 78 and 79.
b. The Company has become aware of an error in Exhibit A-12 (SAH-3) and plans to file a revised exhibit to correct the error. Please see attachment U20963-SA-CE-294-Coker_ATT_1 for the proposed revised exhibit to be filed.

U20963-SA-CE-294-Coker_ATT_1					
MICHIGAN PUBLIC SERVICE COMMISSION		**Schedule: B-5.2**		Case No.:	U-20963
				Exhibit No.:	A-12 (SAH-3)
Consumers Energy Company		Corrected		Schedule:	B-5.2
Summary of Actual and Projected Electric Capital Expenditures				Page:	4 of 9
For the years 2019 through 2022				Witness:	SAHugo
($000's)				Date:	March 2021

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line		**12 Months Ended**	**12 Months Ended**	**12 Months Ending**	**24 Months Ending**	**12 Months Ending**
No.	**Description**	**12/31/2019**	**12/31/2020**	**12/31/2021**	**12/31/2021**	**12/31/2022**
1	Contractor	$ 146,029	$ 91,326	$ 254,726	$ 346,053	$ 366,721
2	Labor	$ 21,521	$ 12,261	$ 4,155	$ 16,416	$ 4,288
3	Materials	$ 21,686	$ 12,562	$ 16,786	$ 29,348	$ 18,814
4	Business Expenses	$ 533	$ 253	$ 448	$ 700	$ 607
5	Contingency	$ 0	$ -	$ 8,577	$ 8,577	$ 18,689
6	Other (Loadings, Chargebacks)	$ (20,138)	$ 13,137	$ 13,246	$ 26,383	$ 34,596
				$ -		
	Total	$ 169,632	$ 129,539	$ 297,938	$ 427,477	$ 443,716

U20963-AG-CE-586
Page **1** of **1**

Question:

25. Refer to Exhibit A-35 (RTB-2). Please provide the following information in Excel:

a. Expand this schedule to include a column and amounts for each line for actual expenditures in 2020.
b. For each line item, please provide the number of units, projects or activities that support the capital expenditures for each year actual 2015 to 2020 and forecasted for 2020 to 2022.

Response:

a. Please see Attachment 1 to this discovery response.

b. This information cannot be provided as requested. As detailed throughout my testimony, units, projects, and/or activities are generally enumerated at the investment category level, whereas Exhibit A-35 (RTB-2) is broken down at the sub-program level. Units, projects, and activities do not roll up to a single sub-program level number in the manner requested by this interrogatory. Furthermore, investment categories did not exist prior to 2018, when they were introduced as part of the 2018 Electric Distribution Infrastructure Investment Plan. Finally, some investment categories have moved between sub-programs since 2018, some investment categories have been discontinued, and some new ones have created. I provide units, projects, and activities to support 2022 test year spending at the investment category level throughout my testimony and exhibits and did so for 2021 spending in my testimony and exhibits in Case No. U-20697.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

MICHIGAN PUBLIC SERVICE COMMISSION — AG-CE-586 ATT 1
Consumers Energy Company
Projected Capital Expenditures
Electric Distribution
Summary of 5yr Historical Electric Capital Expenditures
($000)

Case No.: U-2XXXX
Exhibit No.: A-XX (RTB-2)
Page: 1 of 1
Witness: RTBlumenstock
Date: March 2021

Line No.	(a) Program / Sub-Program	(b) Witness	(c) 2015 Actuals	(d) 2016 Actuals	(e) 2017 Actuals	(f) 2018 Actuals	(g) 2019 Actuals	(h) 5yr Average	(i) 2020 Projected Bridge Year	2020 Actuals Bridge Year	(j) 2021 Projected Bridge Year	(k) 2022 Projected Test Year	(l) Test Year vs 5yr Ave Variance (k - h)
1	Lines New Business - LVD	RTBlumenstock	45,644	43,039	65,878	87,057	83,474	65,018	86,260	91,709	93,113	98,546	33,528
2	Large New Business Projects	RTBlumenstock	29	(37)	-	-	-	(2)	-	-	-	-	2
3	Lines Strategic Customers - HVD	RTBlumenstock	7,035	27,864	7,113	(6,179)	6,464	8,459	6,036	4,038	17,281	10,000	1,541
4	Metering New Business - LVD	RTBlumenstock	5,171	5,266	8,075	9,396	13,637	8,309	10,519	11,591	7,703	9,326	1,017
5	Transformers New Business - LVD	RTBlumenstock	12,136	8,852	13,063	11,421	21,595	13,413	12,200	12,986	12,344	12,610	(803)
6	Metro New Business	RTBlumenstock	2,760	3,243	2,411	3,451	7,384	3,850	4,500	4,562	3,500	3,675	(175)
7	**New Business**		**72,775**	**88,227**	**96,540**	**105,146**	**132,554**	**99,048**	**119,515**	**124,886**	**133,942**	**134,158**	**35,109**
8	Lines Reliability - LVD	RTBlumenstock	25,092	48,617	37,877	36,866	35,745	36,839	30,684	33,257	40,658	45,862	9,023
9	Lines Reliability - HVD	RTBlumenstock	14,640	37,825	17,325	42,708	47,816	32,063	22,679	22,290	63,909	78,439	46,376
10	Substations Reliability - LVD	RTBlumenstock	8,936	11,135	14,112	10,198	13,577	11,592	13,060	12,583	13,307	15,500	3,908
11	Substations Reliability - HVD	RTBlumenstock	3,458	3,850	4,342	2,848	4,676	3,835	5,864	6,480	5,223	5,390	1,555
12	System Protection	RTBlumenstock	1,899	1,569	4,244	3,000	3,141	2,771	2,973	2,626	2,344	2,364	(407)
13	Repetitive Outages - LVD	RTBlumenstock	10,322	8,353	6,270	4,367	6,572	7,177	4,749	4,350	7,718	10,196	3,019
14	Metro Reliability	RTBlumenstock	4,209	2,518	949	969	3,263	2,382	3,250	3,516	5,647	5,575	3,193
15	Grid Capabilities: Automation	RTBlumenstock	13,758	17,601	13,924	22,620	40,805	21,742	44,457	43,593	56,832	61,495	39,753
16	Grid Capabilities: Advanced Technologie	RTBlumenstock	-	-	-	-	18,377	3,675	18,871	21,458	14,394	21,906	18,230
17	Substations Comm Upgrades	RTBlumenstock	508	1,324	11,903	24,114	30,871	13,744	8,252	7,213	300	-	(13,744)
18	Lines and Subs Rehabilitation HVD	RTBlumenstock				-	-	-	13,967	15,461	38,521	40,974	40,974
19	Substations Rehabilitation LVD	RTBlumenstock				-	-	-	8,900	9,838	14,500	13,500	13,500
20	Lines Rehabilitation - LVD	RTBlumenstock				31,949	22,403	27,176	21,397	22,331	36,183	53,666	26,490
21	Metro Rehabilitation	RTBlumenstock				-		-	4,355	6,181	4,353	4,570	4,570
22	Grid Storage	RTBlumenstock				-	5	3	3,810	2,552	5,980	10,000	9,997
23	**Reliability**		**82,822**	**132,792**	**110,946**	**179,639**	**227,252**	**146,690**	**207,267**	**213,729**	**309,869**	**369,437**	**222,746**
24	Lines Capacity - LVD	RTBlumenstock	16,871	14,517	18,332	12,295	4,691	13,341	9,238	9,836	11,321	13,184	(157)
25	Lines & Subs Capacity - HVD	RTBlumenstock	15,612	20,965	16,823	16,545	21,989	18,387	21,501	19,247	20,203	20,100	1,713
26	Substations Capacity - LVD	RTBlumenstock	7,209	18,044	13,696	15,890	11,197	13,207	9,890	10,686	14,000	14,000	793
27	Transformers Capacity - LVD	RTBlumenstock	3,944	3,219	4,610	3,221	2,852	3,569	813	866	823	841	(2,729)
28	New Business Cap - LVD	RTBlumenstock	-	-	-	10,260	16,515	5,355	14,559	17,767	12,187	12,411	7,056
29	Conservative Voltage Reduction CVR	RTBlumenstock				-	82	41	1,700	1,937	4,088	4,154	4,113
30	Interconnections - LVD Lines	RTBlumenstock				-		-	50	-	-	-	-
31	Interconnections - HVD Lines	RTBlumenstock				-		-	-	-	-	150	150
32	Interconnections - LVD Substations	RTBlumenstock				-		-	-	-	-	-	-
33	Interconnections - HVD Substations	RTBlumenstock				-		-	-	-	-	-	-
34	**Capacity**		**43,636**	**56,745**	**53,461**	**58,211**	**57,325**	**53,876**	**57,751**	**60,338**	**62,622**	**64,840**	**10,964**

MICHIGAN PUBLIC SERVICE COMMISSION — AG-CE-586 ATT 1

Consumers Energy Company
Projected Capital Expenditures
Electric Distribution
Summary of 5yr Historical Electric Capital Expenditures
($000)

Case No.: U-2XXXX
Exhibit No.: A-XX (RTB-2)
Page: 1 of 1
Witness: RTBlumenstock
Date: March 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)		(j)	(k)	(l)
Line No.	Program / Sub-Program	Witness	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	5yr Average	2020 Projected Bridge Year	2020 Actuals Bridge Year	2021 Projected Bridge Year	2022 Projected Test Year	Test Year vs 5yr Ave Variance (k - h)
35	Lines Failures - LVD	RTBlumenstock	76,151	66,860	84,508	66,302	95,719	77,908	106,079	117,087	82,540	84,031	6,123
36	Lines & Subs Failures - HVD	RTBlumenstock	14,877	13,206	17,623	27,756	24,889	19,670	8,180	6,782	4,180	4,120	(15,550)
37	Substations Failures - LVD	RTBlumenstock	7,613	9,399	15,451	20,039	20,718	14,644	8,293	9,175	7,001	7,000	(7,644)
38	Metering Failures - LVD	RTBlumenstock	5,719	7,272	11,805	11,632	10,989	9,483	10,361	10,999	9,842	11,818	2,335
39	Transformers Failures - LVD	RTBlumenstock	14,260	14,754	20,747	14,642	16,298	16,140	14,098	15,006	14,265	14,572	(1,568)
40	Streetlight-Mercury Vapor / LED	RTBlumenstock	2,701	2,193	2,080	1,840	2,373	2,237	1,057	1,119			(2,237)
41	Streetlighting Center Suspension	RTBlumenstock				-		-	-	-	1,315	3,000	3,000
42	Metro Failures	RTBlumenstock	1,517	5,047	3,643	2,547	3,003	3,152	1,000	1,041	1,100	1,110	(2,041)
43	**Demand Failures**		**122,838**	**118,731**	**155,857**	**144,758**	**173,990**	**143,235**	**149,068**	**161,208**	**120,243**	**125,651**	**(17,583)**
44	Lines Relocations - LVD	RTBlumenstock	19,368	14,362	23,154	34,092	40,449	26,285	35,685	32,961	48,945	52,506	26,221
45	Lines Relocations - HVD	RTBlumenstock	1,056	288	168	1,986	(382)	623	900	1,906	900	900	277
46	Metro Relocations	RTBlumenstock	7,325	4,854	4,791	4,428	3,615	5,003	3,290	3,815	3,850	4,043	(960)
47	**Asset Relocations**		**27,749**	**19,504**	**28,113**	**40,505**	**43,682**	**31,911**	**39,875**	**38,683**	**53,695**	**57,449**	**25,538**
48	Computer & Equipment	RTBlumenstock	113	76	430	77	2	139	25	2	75	75	(64)
49	Tools	RTBlumenstock	2,178	3,377	1,903	3,822	4,084	3,073	5,507	3,611	8,872	8,955	5,882
50	System Control Projects	RTBlumenstock	88	2	619	1,002	2,325	807	2,157	976	6,699	4,944	4,137
51	Facilities Security	RTBlumenstock	-	1	(1)	-		-		-			-
52	NERC/NESC Compliance	RTBlumenstock	-	-	-	-		-		-			-
53	Substation Fall Protection	RTBlumenstock	196	80	6	5		72		-			(72)
54	Grid Technologies	RTBlumenstock				-		-			56	757	757
55	**Electric Other**		**2,575**	**3,536**	**2,957**	**4,906**	**6,410**	**4,077**	**7,689**	**4,589**	**15,702**	**14,731**	**10,654**
56	**Total Capital Electric D&T**		**352,395**	**419,535**	**447,874**	**533,167**	**641,213**	**478,837**	**581,166**	**603,433**	**696,073**	**766,266**	**287,429**

Question:

31. Refer to page 21, lines 8-15 of Mr. Gregory Griffin's direct testimony. Please:
a. Explain why capital orders are increasing and O&M orders are decreasing.
b. Provide the number of capital orders and the number of O&M orders, separately, by year from 2016 to 2022 and the related dollar amounts in Excel. Explain how the 2021 and 2022 numbers and forecasted amounts were determined.

Response:

- **a.** The capital orders are increasing because the Company is converting all Cobrahead fixtures to LED upon failure rather than try to repair the light. Because the conversion to LED is accounted for as capital and the repair work (e.g. bulb replacement) most likely would have been accounted for as O&M, the number of capital orders is increasing, and the number of O&M orders is decreasing.
- **b.** See below for the historical values from 2016 through 2020. The O&M forecasted amounts for 2021 and 2022 were determined by utilizing the 2019 and 2020 actual results. The O&M projection for 2021 is $1.656 million and $1.752 million for 2022. The Company does not forecast the number of O&M orders, only the projected expense. The Company is forecasting a total of 24,675 capital orders for 2021 and 2022. The increase in the number of capital orders is based upon the conversions of HID cobrahead lights to LED cobrahead lights upon failure as discussed in my direct testimony at page 18, lines 12-18. The total projected cost of $19.494 million and $19.846 million is based upon an average cost of $790 per order in 2021 and $804 per order in 2022, respectively.

O&M			
Year	**Total Spend**	**# of Orders**	**$ Per Order**
2016	$ 1,654,230.54	24738	$ 67
2017	$ 1,637,464.25	19986	$ 82
2018	$ 2,206,398.49	14946	$ 148
2019	$ 1,759,241.04	9646	$ 182
2020	$ 1,679,695.62	8139	$ 206

Capital			
Year	**Total Spend**	**# of Orders**	**$ Per Order**
2016	$ 2,534,661.27	4131	$ 614
2017	$ 2,578,376.28	5028	$ 513
2018	$ 3,705,708.21	7968	$ 465
2019	$ 8,428,721.42	14590	$ 578
2020	$ 10,485,435.94	13599	$ 771

Gregory R Griffin

Gregory R. Griffin
June 4, 2021

Executive Director – Electric Design

Question:

30. Refer to page 13, lines 3-9 of Mr. Gregory Griffin's direct testimony. Please:
a. Provide the total company cost for this project by year from inception to completion and the portion applicable to the electric business.
b. Provide the current phase that the project is in and a timeline of the remaining phases with start and completion dates.

Response:

a. Following are the current projected total company and electric business costs for the Streetlights Outage & Restoration Tracking Application project for Release 1 and 2 by year from inception to completion.

	Total Company		Electric	
	Capital	O&M	Capital	O&M
2020 Actual	$ 0.58	$ 0.20	$ 0.58	$ 0.20
Current 2021 Projected	$ 3.33	$ 0.52	$ 3.33	$ 0.52

b. This project is currently in define phase for Release 2.

The timeline of the remaining phases for the Streetlights Outage & Restoration Tracking Application project is as follows. A phase starts immediately upon completion of the preceding phase.

Define Phase Completion Release 2 – 06/30/2021
Execution Phase Completion Release 2 – 11/19/2021
Go-Live Completion Release 2 – 11/22/2021
Close Phase Completion Release 2 – 12/17/2021

Jeffrey D Tolonen

Jeffrey D. Tolonen
June 4, 2021

Question:

29. Refer to page 11, lines 7-8 of Mr. Gregory Griffin's direct testimony. Why not ask municipalities to report outages most frequently?

Response:

While the Company could ask municipalities to report outages more frequently in order to avoid spikes in workload, the Company believes that its recently released streetlight outage and reporting application will simplify the reporting process and ultimately lead to more frequent outage reporting. The Company is also investigating other mechanisms such as advanced controls through which streetlight outages will be reported more frequently.

Gregory R. Griffin
June 3, 2021

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

Question:

28. Refer to page 10, lines 13-19 of Mr. Gregory Griffin's direct testimony. Please explain what is wrong with asking customers to report problems or outages of streetlights. It would seem this is a very cost-effective method.

Response:

The Company agrees that having customers report streetlight outages is a very cost effective method. The Company has recently released its streetlight outage and reporting application which the Company believes will simplify the customer streetlight reporting process.

Gregory R. Griffin
June 3, 2021

Executive Director – Electric Design

Question:

12. Please refer to Figure 35, "LVD Asset Relocations Investment Category Expenditures", found on page 106 of Mr. Blumenstock's direct testimony.
a. Please provide the projected capital expenditures for 2021 for each of the three investment categories. In other words, expand the table to include 2021 projected expenditures.
b. Please provide the actual capital expenditures for 2017, 2018, 2019, and 2020 for each of the three investment categories. In other words, expand the table to include 2017 - 2020 actual expenditures.

Response:

Please see the table below. For 2020, this table reflects actual 2020 year-end spending, while Exhibit A-35 (RTB-2), line 44, column (i) reflected projected 2020 spending. For 2021, this table reflects current projected year-end totals, which differ from what is shown in Exhibit A-35 (RTB-2), line 44, column (j).

Investment Categories	***2017***	***2018***	***2019***	***2020***	***2021 (Projected)***
Relocations due to 3rd-party requests	$15,876,500	$21,814,300	$16,617,700	$23,894,400	$25,841,000
LVD Underbuild relocations	$2,320,700	$5,884,100	$13,000,500	$3,706,400	$6,624,000
Make-ready work	$4,956,500	$6,393,300	$10,830,900	$5,360,500	$14,146,000
Total	$23,153,700	$34,091,700	$40,449,100	$32,961,300	$46,611,000

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
April 23, 2021

U20963-ST-CE-109
Page **1** of **1**

Question:

22. Please refer to Figure 45, "Grid Modernization Investment Category Expenditures and Units", found on page 168 of Mr. Blumenstock's direct testimony.

    a. Please provide the projected capital expenditures for 2021 for each investment category. In other words, expand the table to include 2021 projected expenditures.

    b. Please provide the actual capital expenditures for 2017, 2018, 2019, and 2020 for each investment category. In other words, expand the table to include 2017-2020 actual expenditures.

Response:

See the table below. Please note that Figure 45 in my direct testimony only reflects investment categories that have spending in the 2022 test year. In 2017 through 2021, the Grid Modernization sub-program included other investment categories besides these. Therefore, the spending shown in this discovery response may not align with the total Grid Modernization spending show in Exhibit A-35 (RTB-2), lines 15 and 16.

	Actual				Projected
Investment Categories	**2017**	**2018**	**2019**	**2020**	**2021**
DSCADA	7,923,358.14	8,604,432.89	8,204,138.68	18,259,090.55	$20,899,000
ATR Loops	2,903,924.34	6,999,644.41	18,791,469.74	12,579,110.76	$21,258,000
Line Sensors	0.46	2,437,403.51	1,549,692.07	7,096,826.27	$4,274,983
Regulator Controllers	200,764.02	2,489,473.12	8,185,348.67	5,095,217.87	$9,897,572
LVD Capacitor Upgrades & Replacements			96,730.84	576,655.17	$502,438
ADMS Expansion	-	-	-	-	-
DERMS	-	-	-	60,227.00	$1,187,710
Electric Grid Analytics	-	-	-	250,505.32	$748,000
Reliability Predictive Analytics	-	-	-	-	$3,549,650
Electric SIMS Conversion	-	-	-	-	-
Grid Modernization Incubator	-	-	-	-	$2,521,505
Electric Grid Telecom Device Management	-	-	-	-	$91,000
Electric Distribution Asset Management	-	-	-	-	$992,000

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
April 23, 2021

U20963-ST-CE-691
Page **1** of **1**

Question:

26. Refer to Figure 54, "LVD Substations Rehabilitation Investment Category Expenditures and Units", found on page 201 of Mr. Blumenstock's direct testimony.

  A. Please provide the projected capital expenditures for 2021 for each of the two investment categories. In other words, expand the table to include 2021 projected expenditures.

  B. Please provide the actual capital expenditures for 2017, 2018, 2019, and 2020 for each of the two investment categories. In other words, expand the table to include 2017 -2020 actual expenditures.

Response:

Please see below. The LVD Substations Rehabilitation sub-program did not exist prior to 2020. Note that the 2020 actual spending is different from what was reflected in my exhibits for the LVD Substations Rehabilitation spending program, because the number in my exhibits was based on a projected number before 2020 was over. Also note that the 2021 projection in this response is higher than the amount shown in my exhibits, as the Company has pulled forward some projects that were originally not scheduled until later (see page 116, lines 9 through 14, of my direct testimony).

REHABILITATION Investment Categories	2020 Actual	2021 Projected
Allis Chalmers transformer replacements	$ 6,541,995	$ 11,820,000
Equipment replacement and regulatory	$ 3,296,503	$ 4,165,500
Total	**$ 9,838,498**	**$ 15,985,500**

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 14, 2021

Question:

22. In a format similar to Exhibit A-48 (RTB-15), please list all projects that have been or will be completed in the System Control Projects sub-program in 2021. Please include actual or projected spending for each project.

Response:

Please see Attachment 1 to this discovery response. Note that some line items have similar or identical names to projects listed in Exhibit A-48 (RTB-15), representing projects with work and spending in both 2021 and 2022.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 13, 2021

					20963-ST-CE-687
					Attachment 1
(a)	(b)	(c)	(d)	(e)	(f)
		Planned 2021			
Sub-Program	**Project Description, Line, Substation, or Location**	**Year Sper**	**Units**	**Unit Type**	**Investment Category**
Other					
System Control Project	Add a Bypass Switch at the Wealthy St. Substation on the 1577 bı	65	1	Project	HVD Operations Projects
	Bath 46kV line – Replace the Bath Jct. 5103 switch with a 600A sw	88	1	Project	HVD Operations Projects
	Coleman 46kV line – Reconductor ≈ 0.4 mi of 115 Cu conductor fr	190	1	Project	HVD Operations Projects
	Convert the Clyde Rd 6297 and 6285 switches into MOAB switche	300	1	Project	HVD Operations Projects
	Hughes Road 3/4 mile reconductoring	800	1	Project	HVD Operations Projects
	Replace Beveridge 46kV TB1 Disconnect Switches.	65	1	Project	HVD Operations Projects
	Line Sensor Installations on the following lines	1,275	124	Total Sens	HVD Operations Projects
	Maple city		3	Sensors	HVD Operations Projects
	Auburn		6	Sensors	HVD Operations Projects
	Wirtz Road		4	Sensors	HVD Operations Projects
	Venice		5	Sensors	HVD Operations Projects
	Ashley		4	Sensors	HVD Operations Projects
	Carson City (A / Deja)		4	Sensors	HVD Operations Projects
	Carson City (B / Alma)		1	Sensors	HVD Operations Projects
	Waldron		5	Sensors	HVD Operations Projects
	McBain		3	Sensors	HVD Operations Projects
	Gun Lake		3	Sensors	HVD Operations Projects
	Union St		4	Sensors	HVD Operations Projects
	Lake Odessa		4	Sensors	HVD Operations Projects
	Stanton		2	Sensors	HVD Operations Projects
	Chelsea		3	Sensors	HVD Operations Projects
	Spring Lake		1	Sensors	HVD Operations Projects
	St. Johns		3	Sensors	HVD Operations Projects
	Tenth St		1	Sensors	HVD Operations Projects
	Davidson		6	Sensors	HVD Operations Projects
	Harlem		2	Sensors	HVD Operations Projects
	Prescott		2	Sensors	HVD Operations Projects
	Textron		4	Sensors	HVD Operations Projects
	Bellevue		4	Sensors	HVD Operations Projects
	Lincoln		4	Sensors	HVD Operations Projects
	Casino		3	Sensors	HVD Operations Projects
	Markey		3	Sensors	HVD Operations Projects
	Goodale		4	Sensors	HVD Operations Projects
	Springfield		5	Sensors	HVD Operations Projects
	Oscoda		3	Sensors	HVD Operations Projects
	Hamilton		3	Sensors	HVD Operations Projects
	Merrill		5	Sensors	HVD Operations Projects
	Hughes Road		9	Sensors	HVD Operations Projects
	Big Rapids		5	Sensors	HVD Operations Projects
	Homestead		6	Sensors	HVD Operations Projects
	SCADA - Test RTUs to support DER integration into CE SCADA	131	1	Project	Operating Technology Enhancements
	Storm Restoration - Enhance resource management tools and OI	870	1	Project	Operating Technology Enhancements
	Emergency Operations Center changes due to ICS	44	1	Project	Operation Center Modifications
	SCC & DCC Control Room Modifications	1,131	1	Project	Operation Center Modifications
	Operation Center Video Walls	1,740	1	Project	Operation Center Modifications
	System Control Projects Total	**6,699**			

Question:

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

   a. Please detail the approval process for a project from project identification to when it is presented in a rate case before the Commission for approval. Please provide any internal guidance documentation that can provide Staff with a clear understanding of the individual steps in the project approval process and the requirements for a project to advance to the next stage of development.

   b. Are there any additional requirements for internal Company approval of capital funds for projects above a certain cost threshold? If so, please detail any additional steps in the approval process.

   c. Please provide the project approval status of each qualifying project shown on Exhibit A-12 (SAH-3), Sch. B-5.2, pages 7 through 9. For projects that have not received internal budgetary approval, please provided the expected date of such approval.

Response:

Objection by Counsel: The Company objects to this request to the extent that it seeks confidential business information. The disclosure of such information could cause harm to the Company and its customers. The requested confidential business information will only be provided subsequent to the execution of a suitable confidentiality and nondisclosure agreement. Subject to this objection, and without waiving it, the Company provides the following response:

a. See confidential attachment U20963-ST-CE-083_CONF_ATT_1 for the general process. Once approved through this process, the data is used to establish the Rate Case testimony, exhibits and work papers.

b. Yes, projects greater than $50M are required to go through additional approval documented in the policy attached as confidential attachment U20963-ST-CE-083_CONF_ATT_2.

c. All projects shown on Exhibit A-12 (SAH-3), Sch. B-5.2, pages 7 through 9 have been processed through the Long-Term Financial Plan Process which is documented within Attachment U20963-ST-CE-083_CONF_ATT_1. Ludington Overhaul, Hardy Auxiliary Spillway, 2019 Solar Bid Event and the 2020 Solar Bid Event are the projects that require additional approval as outlined in U20963-ST-CE-083_CONF_ATT_2. Currently, the Hardy Auxiliary Spillway and the 2020 Solar Bid Event are projects that have not received this approval. The Hardy Auxiliary Spillway is projected to receive this approval in November 2021 and the 2020 Solar Bid Event is projected to receive this approval following execution of a contract and based upon the current timeline, the earliest date for this approval is November 2021.

Scott A. Hugo
April 19, 2021

Director – Generation Asset Strategy

Question:

26. Refer to page 82, lines 18-29, page 83, and page 84, lines 1-6 of Mr. Hugo's direct testimony.

a. For each project, please provide the current phase the project is in, when this phase started and will be completed, the remaining phases of the project with start and completion dates, and the amount spent in 2020, and forecasted to be spent in 2021, 2022, and future years.

b. For each project, please provide a copy of the Company's project cost estimate document as approved and any accepted construction bids or other bids for services received.

c. For the Five Channels Corewall, Hardy, and Webber projects, please provide a copy of the net present value cost/benefit analyses in Excel with formulas intact and supporting data that shows the capital expenditures for these projects in 2020, 2021, 2022, and future years are economically justified.

Response:

a. The phase and spend per year can be found in Attachment 115 of the Company's Part III filing requirement. This attachment is also included as U20963-AG-CE-898_ATT_1.

b. **Objection of Counsel: Consumers Energy Company objects to this discovery request because it is overly broad and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:**

The project cost can be found in the Concept Approval or Project Charter which was provided by the Company in response to U20963-ST-CE-076.

c. No cost/benefit analysis has been completed for these projects. The projects in question are all classified as FERC requirements or condition based. As described in my testimony, the strategy for the Hydro fleet is to maintain the fleet to ensure safe (both public and employee) and compliant sites. The Five Channels Corewall and Hardy Auxiliary Spillway are required by the FERC, the Webber Overhaul and Generator Rewind is condition based.

Scott A. Hugo
June 2, 2021

U20963-AG-CE-910
Page **1** of **1**

Question:

27. Refer to page 86, lines 30-37, and pages 87-89, of Mr. Hugo's direct testimony.

a. For each project, please provide the current phase the project is in, when this phase started and will be completed, the remaining phases of the project with start and completion dates, and the amount spent in 2020, and forecasted to be spent in 2021, 2022, and future years.

b. For each project, please provide a copy of the Company's project cost estimate document as approved and any accepted construction bids or other bids for services received.

c. For the Croton, Hodenpyl, and Mio projects, please provide a copy of the net present value cost/benefit analyses in Excel with formulas intact and supporting data that shows the capital expenditures for these projects in 2020, 2021, 2022, and future years are economically justified.
28. Refer to page 94,

Response:

a. The phase and spend per year can be found in Attachment 115 of the Company's Part III filing requirement. This attachment is also included as U20963-AG-CE-898_ATT_1.

b.

Objection of Counsel: Consumers Energy Company objects to this discovery request because it is overly broad and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:

The project cost can be found in the Concept Approval or Project Charter which was provided in the Company's response to U20963-ST-CE-076.

c. No cost/benefit analysis has been completed for these projects. The projects in question are all classified as FERC requirements or condition based. As described in my testimony, the strategy for the Hydro fleet is to maintain the fleet to ensure safe (both public and employee) and compliant sites. The Mio Left Retaining Wall is required by the FERC, the Croton Wicket Gates, Hodenpyl projects and Mio Electrical Safety project are condition based.

Scott A. Hugo
June 2, 2021

Question:

31. Refer to page 101, lines 12-25 of Mr. Hugo's direct testimony. Please:

a. Identify the project whose cost was revised and provide the before and after cost amount of the project. Identify also the before and after labor cost included in the total project cost.

b. Provide the amount of overhead costs added to the project in this rate case.

c. Provide the overhead rate applied to each dollar of labor or direct construction costs.

d. Provide the calculation of the overhead rate in Excel with formulas intact and all supporting data.

e. Explain why this additional amount of $3.0 million in construction overheads is necessary. Confirm that the amount of construction overheads is determined based on the amount of capital expenditures included in the rate case forecast? If the capital expenditures were reduced then should not a lower amount of overheads be included in rate base based on the same overhead rate, and the overheads not capitalized should be expensed?

Response:

a. After the Long-Term Financial Plan (LTFP) was reviewed and approved, contract negotiations were completed for the 2019 Solar Event. The result was a $36M reduction in the 2021 project forecast. This project was adjusted down to the $83.8M asked in my testimony. The line item referenced in the question was added as a result of this reduction. As described in my testimony, the funding is to offset the loadings increase in the remainder of the projects. Overhead labor remained the same, but the remaining allocation among the projects was too low for the projects due to the 2019 Solar Event reduction.
b. For the 2019 Solar Event, the 2021 overhead cost is $2.34M.
c. The rate applied for Engineering and Supervision (E&S) was 2.5%, for Administrative and General (A&G) was 21.0% and Pension was 5%. E&S is applied to all direct costs, A&G and Pension are applied to all company labor and E&S.
d. See U20963-AG-CE-914-ATT_1.
e. The base costs have remained consistent, the $3M is not an additional amount to the base. The total people and cost being allocated did not change. As the total capital spending changes, the rate required to clear those base costs is required to change. As explained in my testimony, the late change in the plan, causing significant reduction in the 2019 Solar Event has resulted in the need to adjust loadings, and therefore the remaining projects will be affected by the reallocation. The timing of the project reduction was completed after the LTFP was

approved and timing did not allow for the recalculation of each project. This line item is intended to fund the additional loading to each project.

Scott A. Hugo
June 2, 2021

Director – Generation Asset Strategy

Consumers Energy Company
Engineering/Supervision Allocation
Electric Production - Fossil/Hydro
For the Year 2020

Mth	Overhead Base Allocation	E & S Rate	Capitalized Construction Overheads 5325000 Allocated	Actuals	2005248 WO 0805 Overhead Balance			Total Master Data less Central & Wind(Heartland and Crescent) Total Spend from Master Data File	Wind(Crescent & Heartland)**	Solar	LTSA	Central	=Electric	Directs =Total Spend Based less Central * 92%
1/1					0.20									
Jan	12,548,604	2.04%	(255,991.52)	440,714.69	184,723.37	X	Powerplant	14,164,262				233,801	13,930,461	12,548,604
Feb	6,811,810	2.04%	(138,960.92)	741,328.74	787,091.19	X	Powerplant	7,615,924				211,783	7,404,141	6,811,810
Mar	43,413,420	2.04%	(885,633.77)	741,328.74	642,786.17	X	Powerplant	47,766,958				578,458	47,188,500	43,413,420
Apr	33,351,295	2.33%	(777,085.18)	741,328.74	607,029.73	X	Powerplant	36,891,977				640,569	36,251,408	33,351,295
May	27,235,858	2.33%	(634,595.50)	741,328.74	713,762.97	X	Powerplant	30,201,550				597,356	29,604,194	27,235,858
Jun	32,711,555	2.33%	(762,179.23)	741,328.74	692,912.48	X	Powerplant	36,080,324				524,286	35,556,038	32,711,555
Jul	32,498,803	2.33%	(757,222.11)	741,328.74	677,019.11	X	Powerplant	35,815,732				490,946	35,324,786	32,498,803
Aug	27,327,670	2.33%	(636,734.71)	741,328.74	781,613.14	X	Powerplant	30,082,142				378,153	29,703,989	27,327,670
Sep	41,738,712	2.33%	(972,511.98)	741,328.74	550,429.90	X	Powerplant	45,717,788				349,623	45,368,165	41,738,712
Oct	25,805,390	2.33%	(601,265.59)	741,328.74	690,493.06	X	Powerplant	28,394,199				344,862	28,049,337	25,805,390
Nov	55,373,736	2.33%	##########	741,328.74	141,613.76	X	Powerplant	60,585,251				396,408	60,188,843	55,373,736
Dec	37,352,995	2.33%	(870,324.79)	741,328.74	12,617.71	X	Powerplant	70,975,490		30,000,000		374,408	40,601,082	37,352,995
	376,169,848		(8,582,713.35)	8,595,330.86	8,328,808.97			444,291,597	-	30,000,000	-	5,120,653	409,170,944	376,169,848
	376,169,848						4,147,358.40						376,437,269	
	0.00							Estimated Base Rate					92%	

U20963-AG-CE-594
Page **1** of **1**

Question:

33. Refer to Exhibit A-12 (SAH-3), Schedule B-5.2, page 1. Please provide the same information for actual 2020.

Response:

Please see Attachment U20963-AG-CE-595_ATT_1, page 1.

Scott A. Hugo
May 6, 2021

MICHIGAN PUBLIC SERVICE COMMISSION | **Schedule: B-5.2** | **Schedule: B-5.2**

AG-CE-594/595

Case No.: U-20963
Exhibit No.: A-12 (SAH-3)
Schedule: B-5.2
Page: 1 of 9
Witness: SAHugo
Date: March 2021

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2019 through 2022
($000's)

Generation Capital Expenditures
($000)

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2019	(c) Projected 12 Months Ended 12/31/2020	(d) Historical 12 Months Ended 12/31/2020	(e) Projected Bridge Year 12 Months Ending 12/31/2021	(f) 24 Months Ending 12/31/2021	(g) Year 12 Months Ending 12/31/2022
1	Steam Power Generation						
2	Environmental	$ 7,655	$ 10,779	$ 8,849	$ 13,902	$ 24,681	$ 26,247
3	Routine and Small CapEx	$ 92,097	$ 77,149	$ 76,908	$ 88,923	$ 166,072	$ 61,003
4	Total Steam Production	$ 99,752	$ 87,929	$ 85,757	$ 102,824	$ 190,753	$ 87,251
5	Hydraulic Power Generation						
6	Routine and Small CapEx	$ 28,756	$ 19,603	$ 18,779	$ 34,878	$ 54,481	$ 59,937
7	Total hydraulic production	$ 28,756	$ 19,603	$ 18,779	$ 34,878	$ 54,481	$ 59,937
8	Pumped Storage Generation						
9	Ludington Overhaul	$ 26,301	$ 9,494	$ 8,778	$ 13,780	$ 23,274	$ 875
10	Routine and Small CapEx	$ 9,484	$ 8,418	$ 7,286	$ 19,208	$ 27,626	$ 8,333
11	Total Pumped Storage Generation	$ 35,785	$ 17,912	$ 16,064	$ 32,988	$ 50,900	$ 9,208
12	Other Production Plant						
13	Routine and Small CapEx	$ 5,338	$ 4,095	$ 3,736	$ 127,248	$ 131,343	$ 287,319
14	Total Other Production Plant	$ 5,338	$ 4,095	$ 3,736	$ 127,248	$ 131,343	$ 287,319
15	Grand Total	$ 169,632	$ 129,539	$ 124,336	$ 297,938	$ 427,477	$ 443,716

U20963-AG-CE-562
Page **1** of **1**

Question:

1. Refer to page 15, lines 9-15, of Mr. Bartholomew's direct testimony. Please provide a detailed timeline for the Lansing Service Center project with start and completion dates for each phase of the projects and the costs to be incurred during each phase.

Response:

Please reference Exhibit A-27 (SJB-11) for projected construction costs, by year, associated with the project.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

Operations Support

U20963-AG-CE-563
Page **1** of **1**

Question:

2. Refer to page 16, lines 6-14, of Mr. Bartholomew's direct testimony. Please:

a. Provide the number of employees that will be housed at the new Lansing Service Center for each operation.
b. Explain why each of the following functions/operations need to be located at the new Lansing Service Center: Controller/CAO, Electric Grid Integration, Enterprise Project Management/Environmental Services, Information Technology, People & Culture, Public Affairs, Rates & Regulation, and Transformation, Engineering & Operations Support. Explain also what each of those functions entail.

Response:

a. At this time the Company expects the Lansing Service Center to house approximately 412 employees and the following operations: Controller/CAO (5), Customer Experience (11), Customer Experience & Technology (104), Electric Grid Integration (10), Electric Operations (55), Enterprise Project Management/Environmental Services (4), Gas Engineering & Supply (44), Gas Operations (100), Generation Operations & Compression (1), Information Technology (7), Operations (9), Operations Performance (8), Operations Support (21), People and Culture [Human Resources] (7), Public Affairs (3), Rates & Regulation (1), Transformation, Engineering & Operations Support (3), Total (412).

b. Controller/CAO personnel process customer payments submitted via the U.S. Postal Service which are mailed to a Lansing address. Electric Grid Integration personnel operate and control low voltage electric distribution system equipment located both within and outside the Lansing Service Territory. Enterprise Project Management/Environmental Services personnel provide project management services for utility construction work performed in the Lansing Service Territory. Information Technology personnel provide technical support for IT systems and equipment located within the Lansing Service Territory. People and Culture personnel provide human resources support for Lansing area employees and provide technical training and instruction for employees within Lansing Service Territory. Public Affairs personnel regularly interface with governmental agencies in Lansing to address utility service issues and initiatives. Rates & Regulation personnel regularly interface with governmental agencies in Lansing to address utility rate issues. Transformation, Engineering & Operations Support personnel provide multiple support services for utility workers and their work within the Lansing Service Territory including: Facilities Maintenance, Fleet Maintenance, Quality Control, Right Of Way Specialist, Supply Chain material logistics, etc.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

U20963-AG-CE-565
Page **1** of **1**

Question:

4. Refer to page 19, lines 1-4, of Mr. Bartholomew's direct testimony. Please provide a detailed timeline for the Kalamazoo Service Center project with start and completion dates for each phase of the projects and the costs to be incurred during each phase.

Response:

Please reference Exhibit A-27 (SJB-11) for projected construction costs by year associated with the project.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

Operations Support

U20963-AG-CE-567
Page **1** of **1**

Question:

6. Refer to page 20, lines 6-12, of Mr. Bartholomew's direct testimony. Please:

a. Provide the number of employees that will be housed at the new Kalamazoo Service Center for each operation.

b. Explain why each of the following functions/operations need to be located at the new Kalamazoo Service Center: Enterprise Project Management/Environmental Services, Information Technology, Operations Support, Public Affairs, Rates & Regulation, and Transformation, Engineering & Operations Support. Explain also what each of those functions entail.

Response:

a. At this time, the Company expects the Kalamazoo Service Center to house approximately 248 employees and the following operations: Customer Experience (6), Customer Experience and Technology (5), Electric Grid Integration (22), Electric Operations (72), Enterprise Project Management/Environmental (2), Gas Engineering & Supply (23), Gas Operations (71), Generation Operations and Compression (4), Information Technology Operations Support (3), Operations (5), Operations Performance (1), Public Affairs (1), currently there are no Rates & Regulation personnel in Kalamazoo (0), Transformation, Engineering & Operations Support (18), Total (248).

b. The personnel in these functions/operations interact directly with customers or employees within the Kalamazoo Service Territory on a regular basis. By basing these personnel in Kalamazoo the need for unnecessary travel from other locations to and from Kalamazoo is eliminated. Enterprise Project Management/Environmental Services personnel work on and support utility construction projects with project management services and environmental oversight, Information Technology personnel work on and support IT equipment and systems based in the Kalamazoo Service Center and smaller Service Centers located close to Kalamazoo, Operations Support, Public Affairs personnel work with local communities in the Kalamazoo area to support permitting for utility work and new business infrastructure, currently no Rates and Regulations personnel work in Kalamazoo, Transformation, Engineering & Operations Support personnel provide support services for the Kalamazoo Service Center including; new utility service design, Facilities building maintenance, Fleet vehicle and equipment maintenance, Right Of Way Specialists, Supply Chain material logistics, etc.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

U20963-AG-CE-568
Page **1** of **1**

Question:

7. Refer to page 22, lines 3-6, of Mr. Bartholomew's direct testimony. Please provide a detailed timeline for the Hastings Service Center project with start and completion dates for each phase of the projects and the costs to be incurred during each phase.

Response:

Please reference Exhibit A-27 (SJB-11) for projected construction costs by year associated with the project.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

Operations Support

U20963-AG-CE-569
Page **1** of **1**

Question:

8. Refer to page 22, lines 16-21, of Mr. Bartholomew's direct testimony. Please:

a. Provide the number of employees that will be housed at the new Hastings Service Center for each operation.
b. Explain why each of the following functions/operations need to be located at the new Kalamazoo Service Center: Enterprise Project Management/Environmental Services, Information Technology, Operations Support, Public Affairs, Rates & Regulation, and Transformation, Engineering & Operations Support. Explain also what each of those functions entail.

Response:

a. At this time, the Company expects the Hastings Service Center to house approximately 44 employees and the following operations: Customer Experience (2), Electric Grid Integration (2), Electric Operations (20), Gas Engineering & Supply (4), Gas Operations (15), Operations Support (1), Total (44).

b. It is assumed that this question was intended to seek clarification regarding the Hastings Service Center and the response is provided regarding the Hastings Service Center. The personnel in these functions/operations interact directly with customers or employees within the Hastings Service Territory on a regular basis. By basing these personnel in Hastings the need for unnecessary travel from other locations to and from Hastings is eliminated. There are no Enterprise Project Management/Environmental Services personnel based in the Hastings Service Center, there are no Information Technology personnel based in the Hastings Service Center, the Electric and Gas Operations personnel perform utility systems work throughout the Hastings Service Territory, there are no Public Affairs personnel based in the Hastings Service Center, there are no Rates and Regulations personnel based in the Hastings Service Center, Transformation, Engineering & Operations Support personnel provide support services for the Hastings Service Center including fleet vehicle and equipment maintenance, etc.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

Question:

12. Refer to page 26, lines 17-24, of Mr. Bartholomew's direct testimony. Please:
a. Provide a detailed timeline for the Marshall Training Center project with start and completion dates for each phase of the projects and the costs to be incurred during that phase.
b. Is the Marshall Training Center the same training center that the Company presented in Case No. U-20697 under the name Grand Rapids Circuit 501? If yes, explain the purpose for renaming the center and identify how this project differs from the previous proposal. If no, explain how the Marshal project differs from the Grand Rapids Circuit 501.
c. Explain what happened to the Grand Rapids Circuit 501.

Response:

a. 2021

Programming	Q2 2021 – Q3 2021	$10,000
Design	Q3 2021 – Q4 2021	$40,000
2022		
Bidding	Q1 2022	$5,000
Construction	Q2 2022 – Q4 2022	$1,033,000
Equipment	Q4 2022	$1,667,000
IT/Security	Q4 2022	$370,000
2023		
Occupancy	Q1 2023	$0

b. No. The Marshall Training Center project is specifically related to the provision of specialized hands-on training for skilled Utility personnel working on underground electrical distribution systems and equipment. The Circuit 501 facility was a general office environment for engineering personnel. The Marshall Metro City project will provide simulated underground vaults equipped with electrical distribution equipment where instructors can monitor and interact with students as they work through real life training exercises in a controlled environment and practice utilization of associated tools, work methods and safety protocols.

c. The Company re-evaluated the business need for the proposed Circuit 501 facility and determined that the Business Case could no longer be supported. Consequently, the project was cancelled.

Scott Bartholomew

Scott J. Bartholomew
May 7, 2021

Question:

10. Refer to page 25, lines 16-23, of Mr. Bartholomew's direct testimony. Please:

a. Provide a detailed timeline for the UCC project with start and completion dates for each phase of the project and the costs to be incurred during each phase.

b. Explain what you mean by hardened facility.

c. Explain what merchant operations you are referring to, what they entail, the number of employees involved, and why they need to be located at this new facility.

Response:

a. Please reference Exhibit A-20 (SJB-4) for projected costs by year associated with the project.

b. Site located to minimize potential impacts from events transpiring in adjacent area. Site limited to secured access. Facility constructed with reinforced structural system, exterior cladding and roofing system designed to withstand increased wind loads due to severe weather events. Facility served by dual independent electric utility feeds, emergency backup power generating equipment, and uninterruptible power supply systems. Facility equipped with redundant HVAC systems. Facility served by dual independent fiber optic service lines.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

U20963-AG-CE-571 (Partial)
Page **1** of **1**

Question:

10. Refer to page 25, lines 16-23, of Mr. Bartholomew's direct testimony. Please:

a. Provide a detailed timeline for the UCC project with start and completion dates for each phase of the project and the costs to be incurred during each phase.

b. Explain what you mean by hardened facility.

c. Explain what merchant operations you are referring to, what they entail, the number of employees involved, and why they need to be located at this new facility.

Response:

c. Merchant Operations purchases and sells electricity that flows across the grid supplying the electricity needs of our customers. Currently there are 18 employees forecasted in the Merchant Operations Control center that includes support personnel. Future plans to place the Merchant Operations and Real Time Operations in a UCC supports development of a coordination framework that will address the needs of the Company's service territory with the three levels of the electric system: the bulk power level, the distribution level, and the evolving distributed energy resource/customer level. A UCC supports a system wide view to operate the grid and forecast its supply needs using exchanged information in a collaborative space, with new technology/tools and processes for situational awareness required as part of this developing environment.

Brenda L. Houtz
Brenda L. Houtz
May 7, 2021

U20963-AG-CE-572-Partial
Page **1** of **1**

Question:

11. Refer to page 26, lines 15-16, of Mr. Bartholomew's direct testimony. Please:

a. Provide the location of the proposed UCC center.

b. How many people will the UCC center house by operation/function. Identify in which buildings these employees are currently located and why they cannot remain at those locations with technology interconnections and collaboration.

Response:

a. The location for the proposed Unified Control Center has not been determined at this date. Location parameters for site selection include: availability of qualified workforce within local area, availability of dual electric utility feeds to site, availability of dual fiber optic trunk line connections for site, site located outside FEMA designated flood zones, site located outside normal aircraft flight path approach corridors, site not in close proximity to railroad lines, site not in close proximity to major highways, site not in close proximity to facilities manufacturing or processing hazardous materials, etc.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

U20963-AG-CE-572 (Partial)
Page **1** of **1**

Question:

11. Refer to page 26, lines 15-16, of Mr. Bartholomew's direct testimony. Please:

a. Provide the location of the proposed UCC center.

b. How many people will the UCC center house by operation/function. Identify in which buildings these employees are currently located and why they cannot remain at those locations with technology interconnections and collaboration.

Response:

b. It is currently expected that the Unified Control Center will house 95 Control/Dispatch Employees, 40 Real Time Operations Support employees, 25 Merchant Operation Center employees, 20 Emergency Operation/Restoration Management employees, and 15 IT and Support employees. The functions to be incorporated into the proposed Unified Control Center are currently housed within buildings of standard light frame commercial construction which are non-hardened to survive severe weather events and with single sourced utility services subject to a potential single point of failure. These functions are also currently located in multiple separate buildings which requires that specialized support infrastructure be duplicated and maintained at each building location.

Brenda L. Houtz
May 7, 2021

U20963-AG-CE-871
Page **1** of **1**

Question:

30. Refer to page 15, lines 12-13 of Ms. Houtz's direct testimony. Please:

a. Quantify the efficiency and cost savings to be achieved.
b. Identify the opportunities to be achieved.
c. Identify the specific risk reductions.

Response:

a. The Company is in the process of quantifying cost savings and customer benefits and developing a benefit-cost analysis, which is expected to be completed in 2021.

b. Opportunities identified to be achieved are:
    - Efficiencies include, but are not limited to, reduction of storm resource ramp up time associated with reducing multiple work centers, operational communication effectiveness reducing outage duration, and standardization of operational tools and training that promotes coordination between organizations brought together in a common facility.
    - Cost Savings include, but are not limited to, storm ICS support resource reductions, management of storm field resource used time reduction, outage duration reduction affecting customer loss of revenue impact, reduction of training expenses, and maintenance reduction by utilizing new facilities.

c. Specific risk reductions identified are avoiding communications errors in operating a complex system, reduction of footprint under regulatory requirements, redundancy to maintain continued operations in the event of a crisis, reduction of gap with industry in technology advancement and usage, reduction of response time for disruption of service, and improved pandemic mitigation.

Brenda Houtz

Brenda L. Houtz
May 28, 2021

U20963-AG-CE-873
Page **1** of **1**

Question:

32. Refer to page 17, lines 1-13 of Ms. Houtz's direct testimony.

a. With technology allowing sharing of technical information and visual interactions through computer screens, why is it critically necessary for all functions to be at the same location?

b. Does not the co-location all the functions in the same building increase the risk of a catastrophic event at that location ceasing all operations versus the separate locations for each function as it exist today?

Response:

a. Situational awareness with face to face collaboration among the proposed groups for the UCC provides an environment to support the critical nature of these employee functions. This will allow for gains in interaction efficiencies and relationship reliance, knowledge sharing, human performance error mitigation, and an environment to provide the safe delivery and operational performance required in the distribution and supply of energy to our customers.

b. The functions to be incorporated into the proposed Unified Control Center are currently housed within buildings of standard light frame commercial construction which are non-hardened to survive severe weather or other types of events, and with single sourced utility services subject to a potential single point of failure. Current operations also have limited space to expand covering a loss of another facility and improvement for pandemic mitigation. The proposed UCC will address these current conditions and associated constraints and impact and will be hardened for severe weather and incorporate other redundancies. The Company is also considering alternatives to modify some existing facilities at different locations to provide additional redundancy, while still reducing the number of locations used for these operations.

Brenda Houtz

Brenda L. Houtz
May 28, 2021

U20963-AG-CE-874
Page **1** of **1**

Question:

33. Refer to page 17, lines 14-22 of Ms. Houtz's direct testimony. Please provide the cost/benefit analysis showing that the proposed UCC is economically justified on a net present value basis.

Response:

The Company is in the process of quantifying cost savings and customer benefits and developing a benefit-cost analysis, which is expected to be completed in 2021.

Brenda Houtz

Brenda L. Houtz
May 28, 2021

Question:

15. Refer to page 32, line 16, of Mr. Bartholomew's direct testimony. What specific modifications or recommendations are you proposing to address face to face employee communication?

Response:

This will be accomplished through modifications of current floor plans to accommodate a more modular and open floor plan. These actions will support employees having the right type of safe workspace based on the type of work and number of people meeting.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

Operations Support

U20963-AG-CE-578
Page **1** of **1**

Question:

17. Refer to page 33, lines 1-7, of Mr. Bartholomew's direct testimony. Please:

a. Identify specifically what corrective actions, office modifications and other changes you are proposing and the related expenditures for each such initiative.
b. Explain why these changes and modifications are necessary with employees being vaccinated or taking other personal precautions if they wish, such as wearing a mask while at work.

Response:

a. Generally will be modifying furniture layout in locations where the existing furniture layout does not provide 6 feet of physical distancing between occupants. Additionally, meeting room capacity will be reduced, requiring the creation of additional meeting spaces to accommodate needs for collaborative spaces and improved technology to allow real-time collaboration to occur between onsite personnel and remote personnel. Please see A-19 (SJB-3), line 20, which provides the Return to Facilities projected expenses for the 2021 bridge year and the 2022 test year.

b. These changes and modifications are necessary to conform workspaces to the MIOHSA Emergency Rules, requiring employers to design workspaces to promote 6 feet social distancing.

Scott Bartholomew

Scott J. Bartholomew
May 5, 2021

Question:

18. Refer to page 33, lines 8-18, of Mr. Bartholomew's direct testimony. Please:

a. Provide a specific timeline for your implementation plan with related expenditures, capital and O&M separately, by year.
b. Provide the total amount that the Company expects to pay the architectural consultant by year.

Response:

a. 2021 Capital $4,025,000 Workspace modifications to support physical distancing and collaborative work between onsite and remote personnel.

2022 Capital $5,677,000 Workspace modifications to support physical distancing and collaborative work between onsite and remote personnel.

2021 O&M $432,000 Enhanced disinfection, additional cleaning, sanitizing materials, building signage.

2022 O&M $162,000 Enhanced disinfection, additional cleaning, sanitizing materials, building signage.

b. 2021 O&M $53,946 For the architectural consultant to develop the physical spacing plans, Return to Facilities guidelines, employee training materials, and building signage package.

2022 O&M Relocation and movement of personnel to support physical distancing modifications. This is evolving and accurate costs cannot be determined at this date.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

U20963-AG-CE-581
Page **1** of **1**

Question:

20. Refer to Exhibit A-12 (SJB-1), Schedule B5.5. Please provide the following information:

a. The actual 2020 expenditures in the same format.
b. The actual 2016 to 2018 expenditures by year at the summary level at lines 1, 2 and 3.

Response:

See attachment U20963-AG-CE-581-Bartholomew_ATT_1.

Scott Bartholomew

Scott J. Bartholomew
May 4, 2021

	Historical 12 Mos Ended 12/31/2020		
Asset Preservation	**28,082**		
Contractor	24,796		
Labor	1,236		
Materials	955		
Business Expenses	28		
Other (Loadings, Chargebacks)	1,067		
Computer & Other Equipment	**440**		
Contractor	22		
Labor	4		
Materials	413		
Business Expenses	-		
Other (Loadings, Chargebacks)	-		
Total Capital	**28,522**		

Program Description	Historical 12 Mos Ended 12/31/2016	Historical 12 Mos Ended 12/31/2017	Historical 12 Mos Ended 12/31/2018
Asset Preservation	**18,494**	**21,123**	**25,201**
Computer & Other Equipment	**426**	**373**	**1,046**
Total Capital	**18,920**	**21,496**	**26,247**

MICHIGAN PUBLIC SERVICE COMMISSION

Case No: U-20963
WP-ASC-1

Consumers Energy Corporation
Detailed List of Projected Electric Capital Expenditures
For the Years 2021-2022
($000)

Electric Fleet

Line No.	Program Description	12 months ending 12/31/2021 Projected		12 months ending 12/31/2022 Projected	
1	Transportation Equipment - Lifecycle Replacement	$	34,667	$	19,696
2	Transportation Equipment - LVD	$	27,320	$	-
3	Transportation Equipment - HVD	$	-	$	20,500
4	Telematics	$	7,506	$	-
5	Fleet Tools	$	240	$	240
6	**TOTAL CAPITAL EXPENDITURES**	**$**	**69,734**	**$**	**40,438**

U20963-ST-CE-227
Page **1** of **1**

Question:

61. Page 23, lines 15-16 of Company witness Carveth's testimony identifies $27.320 million for LVD workforce expansion in 2021. Please provide the actual and projected units purchased along with associated costs in 2021.

Response:

Please see the attached exhibit, U20963-ST-CE-227-Carveth_ATT_1. Units Identified as ordered in column "C" of the attached, are expected to be delivered in 2021. Projected units are currently under review to ensure they meet the application in the field. These units are also expected to be delivered in 2021.

Adam S. Carveth
April 26, 2021

U20963-ST-CE-234
Page **1** of **1**

Question:

68. Please support the additional request of $20.5 million on page 27 of Company witness Carveth's testimony for additional HVD workforce and provide the following:
a. Specific unit categories.
b. Number of units.
c. When the additional workforce is planned to be hired.

Response:

Please see attachment U20963-ST-CE-234-Carveth_ATT_1 for unit categories and number of units. This request does not include "trailers," as stated in error in my direct testimony on page 27, line 18. The additional HVD construction workforce is currently planned to be hired prior to the end of 2023, contingent upon the Commission's approval in this proceeding.

Adam S. Carveth
April 28, 2021

Unit Category	Quantity
100' Tandem axle bucket	8
65' Tandem axle digger	8
100' Flextrac Bucket. Offroad Equipment	4
65' Flextrac Derrick. Offroad Equipment	4
Support bucket	8
Support digger	8

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

Question:

69. Page 27 of Company witness Carveth's testimony discusses the Company's intent to spend $20.5 million to support the HVD workforce expansion in the 2022 test year. Please provide the projected number and type of units.

Response:

Please reference response in 20963-ST-CE-234.

Adam S. Carveth
April 28, 2021

U20963-ST-CE-238
Page **1** of **1**

Question:

72. Please provide the projected and actual number of HVD employees hired from 2016-2022. Please provide YTD for 2021 and projected for the remainder of 2021 and 2022.

Response:

73 HVD employees have been hired from 2016-2021 YTD (63 HVD apprentices, 10 journey level). For the remainder of 2021, 35 more HVD apprentice hires are planned. For 2022, 15 more HVD apprentice hires are planned. It is reasonable to expect pending labor market availability and localized demand an additional 2 to 3 journey level hires per year.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
April 26, 2021

U20963-ST-CE-239
Page **1** of **1**

Question:

73. Please provide the projected and actual number of LVD employees hired (both apprentice and journey) from 2016-2022. Please provide YTD for 2021 and projected for the remainder of 2021 and 2022.

Response:

347 LVD employees have been hired from 2016-2021 YTD (244 LVD apprentices, 103 journey level). For the remainder of 2021, 72 more LVD apprentice hires and 36 underground construction hires are planned. For 2022, 72 more LVD apprentice hires and 54 underground construction hires are planned. It is reasonable to expect pending labor market availability and localized demand an additional 15 to 30 journey level hires per year.

Richard T. Blumenstock
RICHARD T. BLUMENSTOCK
April 26, 2021

U20963-ST-CE-240
Page **1** of **1**

Question:

74. Page 27, lines 14-15 of Company witness Carveth's testimony indicate that the number of new units is based on the additional headcount included within the workforce expansion. Please show the relationship between the number of new units and additional employees including a unit per additional employee ratio, excluding COVID-19 protocols.

Response:

Current headcount projections for the HVD construction workforce are 48 full time employees; the company is requesting eight, 100ft bucket trucks to support the HVD construction workforce headcount projections. The projected additional employee to unit ratio for this particular expansion is 6:1.

Adam S. Carveth
April 28, 2021

U20963-AG-CE-928
Page **1** of **1**

Question:

45. Refer to page 27, lines 3-18 of Mr. Carveth's direct testimony. Please:

a. Explain why this section of his testimony shows $20.5 million for Electric Operations Workforce Expansion (EOWE) and page 23, lines 15, of his testimony shows $27.32 million. Which is the correct amount?

b. Provide the list of vehicles and equipment and number of units proposed with supporting analysis showing how he determined the $20.5 million or $27.32 million spending amount in Excel with formulas intact, supporting data, and basis for the forecast.

Response:

a. The amounts stated in the above questions support different projects. $20.5 million is the request in the projected test year of this case to support the HVD expansion. $27.32 million is the projected bridge year spend in this case to support the LVD expansion request. Please see workpaper WP-ASC-1.

b. Please reference 20963-ST-CE-234_Carveth_ATT_1 for number of proposed units and U20963-ST-CE-240 for the basis of the forecast.

Adam S. Carveth
June 2, 2021

U20650-AG-CE-348
Page **1** of **1**

Question:

19. Refer to page 28, lines 7-20, of Mr. Jones' direct testimony. Please explain if the Company issued a Request for Proposal for the Telematics or similar system. If yes, please provide the number of vendors contacted and the number of bids received. Provide a copy of the winning bid and what the Company considers to be the second and third best bids.

Response:

The Company did not issue a specific request for proposal for the Telematics project. The Company met with several Telematics providers to learn what offerings these companies provide. The Telematics providers reviewed were Track-star, Fleetilla, Telogis/Verizon and Utilimarc. During the discovery time frame the Company reviewed information presented and the performance of our current providers, Fleetilla and Track-star. The learnings gathered identified all four of the Telematics Companies provide very similar outputs however how they integrate with other systems or the support provided was very different from conversations we have had with other Utilities. The other three companies do not specifically support the Utility Industry instead are set up to support many different Industries. Utilimarc has positioned themselves to only supporting the Utility Industry. The decision was made to sole source Utilimarc based on the justification that they support Utilities only and have demonstrated performance with other Utilities we have benchmarked or communicated with.

Kyle P. Jones
March 17, 2020

U20650-AG-CE-349
Page **1** of **1**

Question:

20. Refer to Chart 8 on page 29 of Mr. Jones' direct testimony. Please confirm that all the functionalities listed for the Utilimarc Telematics will be implemented for the $7.011 million. If yes, please provide the cost by year from start to completion. If not confirming, please identify the total cost and over what future years.

Response:

Yes, we are projecting all functionalities listed will be implemented for $7.011 per work paper titled Jones_WP_4_GRC in the test year of 2020/2021. Upon approval for the telematics project installation will start to occur in October 2020. Once completed with the installs the telematics will go live and begin reporting many of the functions on chart 8 page 29.

Kyle P. Jones
March 17, 2020

U20650-AG-CE-350
Page **1** of **1**

Question:

21. Refer to page 33, lines 17-22, of Mr. Jones' direct testimony. Please:

a. Identify the year that the $5.5 million of annual capital spending savings and $1.3 million of annual O&M savings begin. If these are not annual savings identify over what time period they will occur.

b. Provide the basis for determining the capital spending and O&M savings.

c. Confirm that the savings are only for the gas business. If not confirming, please provide the total company cost savings for capital and O&M.

Response:

a. The annual savings of $5.5 million of capital spending and $1.3 million of O&M savings is planned to occur in 2021.

b. The determining factors for the capital spend is based on the costs for device purchases and installation costs, IT system overlay and developments, maintenance costs, and air time for the devices. The O&M savings come from the assumed savings in chart 9 along with the calculations addressed in the calculations tab in U20650-AG-CE_ATT_1.

c. The projected assumed savings are only for the Gas Business. Additional savings have been identified and submitted in the Electric Rate Case No. U20697.

Kyle P. Jones
March 18, 2020

Elec and Gas Split per finance = Elec 50.7% Gas 49.3%
These figures below for Gas Operations represent 49.3% of the total cost

Description of Savings for Gas Operations							
Fuel Savings			***Capital***		***O&M***		***Total***
Fleet Fuel Savings - Idle Reduction- 10 Min Per Day- 5508 Veh/Equip		$	129,907	$	32,477	$	162,383
Fleet Fuel Savings - 5% Miles Reduction		$	250,365	$	62,591	$	312,956
Fleet Fuel Savings - Off Road Diesel Tax Recovery		$	221,950	$	55,488	$	277,438
Total Fleet Fuel Cost Benefit		**$**	**602,222**	**$**	**150,555**	**$**	**752,777**
Maintenance Savings			***Capital***		***O&M***		***Total***
Maintenance - Warranty Claims Recovery		$	130,177	$	32,544	$	162,721
Maintenance - 50% Reduction in Jump Starts		$	93,907	$	23,477	$	117,384
Maintenance - Predictive Maintenance - DTC Codes/Troubleshooting (time)/Materials/DVIR		$	208,310	$	52,077	$	280,105
Total Maintenance Cost Benefit		**$**	**432,394**	**$**	**108,098**	**$**	**540,492**
Gas Operations (Daily Time Savings)			***Capital***		***O&M***		***Total***
Gas Lineworker Time Savings Per Day- 45 Min Per Day-460 Employees @ $40 Per Hr. **This is done through Geo-Fencing specific locations to reduce wasted time existing the service center, gas station stops, returning to the service center early or multiple times per day and providing the optimal routes for the drivers to take to the job sites .Having visability to bore crews and welders will reduce wait times for crews performing work**	*45 Min Per Day, 460 Lineworkers @ $40 per hour*	$	2,870,400	$	717,600	$	3,588,000
Gas Service Worker Time Savings Per Day-12 Min Per Day-381 Employees @ $40 Per Hr **This is done through Geo-Fencing specific locations to reduce wasted time existing the service center, gas station stops, returning to the service center early or multiple times per day and providing the optimal routes for the drivers to take to the job sites**	*12 Min Per Day, 381 Lineworkers @ $40 per hour*	$	633,984	$	158,496	$	792,480
Total Daily Time Savings Cost Benefit		**$**	**3,504,384**	**$**	**876,096**	**$**	**4,380,480**
Rental Utilization			***Capital***		***O&M***		***Total***
Gas Ops- Rental Unit Utilization Reduction -	*10% of Annual Rental Cost Reduction*	**$**	**964,969**	**$**	**241,242**	**$**	**1,206,211**
Fleetilla Device Replacment		**$**	**76,345**	**$**	**19,086**	**$**	**95,431**
Grand Total Projected Savings			***Capital***		***O&M***		***Total***
		$	***5,580,313***	***$***	***1,395,078***	***$***	***6,975,391***

Description of Savings for Electric Operations				
Fuel Savings		***Capital***	***O&M***	***Total***
Fleet Fuel Savings - Idle Reduction- 10 Min Per Day- 5508 Veh/Equip		$ 133,596	$ 33,399	$ 166,995
Fleet Fuel Savings - 5% Miles Reduction		$ 257,475	$ 64,369	$ 321,844
Fleet Fuel Savings - Off Road Diesel Tax Recovery		$ 228,253	$ 57,063	$ 285,316
Total Fleet Fuel Cost Benefit		**$ 619,324**	**$ 154,831**	**$ 774,155**
Maintenance Savings		***Capital***	***O&M***	***Total***
Maintenance - Warranty Claims Recovery		$ 133,874	$ 33,468	$ 167,342
Maintenance - 50% Reduction in Jump Starts		$ 96,574	$ 24,143	$ 120,717
Maintenance - Predictive Maintenance - DTC Codes/Troubleshooting (time)/Materials		$ 214,225	$ 53,556	$ 288,059
Total Maintenance Cost Benefit		**$ 444,672**	**$ 111,168**	**$ 576,118**
Electric Operations (Daily Time Savings)		***Capital***	***O&M***	***Total***
Electric Lineworker Time Savings Per Day ***This is done through Geo-Fencing specific locations to reduce wasted time existing the service center, gas station stops, returning to the service center early or multiple times per day and providing the optimal routes for the drivers to take to the job sites .Having visability to circuits and contractors will enhance dispatcher decision making to reduce redundant truck rolls for crews performing work***	*20 Min Per Day, 550 Lineworkers @ $47 per hour*	$ 1,792,190	$ 448,048	$ 2,240,238
Electric Service Worker Time Savings Per Day ***This is done through Geo-Fencing specific locations to reduce wasted time existing the service center, gas station stops and returning to the service center early or multiple times per day. This technology provides the dispatchers real time critical information regarding no-light calls allowing the dispatchers to route the nearest most qualified worker to the request.***	20 Min Per Day, 98 Service workers @ $49 per hour	$ 336,336	$ 84,084	$ 420,420
Electric Meter Operations Worker Time Savings Per Day ***This is done through Geo-Fencing specific locations to reduce wasted time existing the service center, gas station stops and returning to the service center early or multiple times per day. This technology provides the dispatchers real time critical information regarding no-light calls allowing the dispatchers to route the nearest most qualified worker to the request.***	*20 Min Per Day, 41 Meter Worker @ $46 per hour*	$ 130,649	$ 32,662	$ 163,311
Electric Operations - Electronic DVIR Submission *** This will contribute 10 minutes to the 30 minutes described above for the 550 lineworkers***	Reduced Jump Starts, Headlights, Break Fix Overnight, Etc.	Embedded Above	Embedded Above	Embedded Above
Total Daily Time Savings Cost Benefit		**$ 2,259,175**	**$ 564,794**	**$ 2,823,969**
Rental Utilization		***Capital***	***O&M***	***Total***
Electric Rental Expense Reduction - $3,019,944 Annual Expense	10% of Annual Rental Cost Reduction	**$ 241,595**	**$ 60,399**	**$ 301,994**
Grand Total Projected Savings		***Capital***	***O&M***	***Total***
		$ 3,564,766	***$ 891,192***	***$ 4,476,235***

U20963-AG-CE-926
Page **1** of **1**

Question:

43. Refer to page 25, line 14 of Mr. Carveth's direct testimony. Please:

a. Provide a status report on the implementation of the Telematics technology and a comparison of the actual costs versus projected costs in total and for the electric business.

b. Provide a copy of the projected cost savings in total and the amount applicable to the electric business, identify and explain any changes in costs savings from those presented in the prior electric and gas rate cases.

Response:

a. Currently, 82% percent of the planned Telematic devices have been installed. 82% equates to 5790 installed vs a target of 7066. Actual vs projected costs are in the chart below.

	Electric Actuals (through April)	Electric Total Year Projections	YTD Total Actuals (through April)	Total Year Projections
Telematics	$ 2,630	$ 7,506	$ 6,883	$ 14,817

b. Refer to Page 36 of Jones testimony in U-20697 for projected cost savings applicable to the electric business and page 34 of Jones testimony in U-20650 for projected cost savings applicable to the gas business. Because the install is currently taking place, there are no changes in cost savings from the information being referenced to above.

Adam S. Carveth
June 2, 2021

Question:

15. Refer to page 19, lines 9-13 of Ms. Anita Griffin's direct testimony. Please:
a. Provide the total company cost for this project by year from inception to completion and the portion applicable to the electric business.
b. Provide the current phase that the project is in and a timeline of the remaining phases with start and completion dates.
c. Identify specifically what the $292,000 and $500,000 will be spent on.

Response:

A:

	2019	2020	2021	2022	2023	2024	2025
Capital	-	**2,747,711.93**	**3,400,000.00**	**3,447,664.00**	**673,584.00**	-	-
Elec	-	1,840,966.99	1,734,000.00	1,758,308.64	343,527.84	-	-
Gas	-	906,744.94	1,666,000.00	1,689,355.36	330,056.16	-	-
O&M	**119,250.43**	**952,996.36**	**1,245,000.00**	**1,722,325.00**	**1,557,125.00**	**1,500,000.00**	**528,000.00**
Elec	59,625.19	693,433.08	1,041,650.00	1,441,012.00	1,307,985.00	1,260,000.00	443,520.00
Gas	59,625.24	259,563.28	203,350.00	281,313.00	249,140.00	240,000.00	84,480.00
* EWR funds 1/3rd the O&M cost							

B:

The project is in the execute phase.

Remaining Milestones:

- RFP - 2019
- R1: 4/6/20 to 9/25 – CRM platform setup, data configuration for sales lifecycle
- R2: 9/26 to 11/19 – Data conversion from legacy systems, account management configuration, EWR product catalog configuration
- R3: 11/20 to 12/17 – Initial configuration of marketing and campaign management, sales dashboards, reporting

- R6: 4/15/21 to 6/23/21 - Email Management, Marketing Approval workflows, and Contact Management R6: 4/15/21 - 6/23/21
- R7: 6/24/21 to 9/1/21 - Outage data and sales lifecycle

- R8: 9/2/21 to 11/10/21 Centralized eligibility and enrollments
- Scope TBD R9: 11/11/21 to 12/31/21

C:

The $292,000 will be spent on labor for IT system modifications, vendor support/licensing fees, and labor related to project management/user acceptance.

The $500,000 is not part of the CRM project; it will be used for the established role of Small Business Experience Manager to help expand historic understanding of what small business customers value and ensure that investments are meaningful. The Company is taking holistic steps to improve the quality of customer data, thus improving the effectiveness of communications and message targeting. For instance, only about 60% of contacts have an email address on file. The Company is in the process of restructuring the consumersenergy.com/business website for easier navigation specifically tailored to small business customers. Additionally, the Company is preparing a high-value service bundle specifically designed for small and medium businesses. This package of services will demonstrate commitment to independent small businesses and to the underlying health of Michigan's small business communities.

The approximate breakout of this expense is as follows:

- $75,000 experience design and customer research
- $50,000 data quality improvements
- $200,000 website redesign and business content
- $125,000 business service bundle development/launch
- $50,000 targeted communications and promotions

Anita J. Griffin
June 3, 2021

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

Question:

16. Refer to page 20, lines 8-23 of Ms. Anita Griffin's direct testimony. Please provide the net present value cost/benefit analysis in Excel with formulas intact that economically justifies this project.

Response:

Please refer to the attachment.

Anita J. Griffin
June 4, 2021

Year		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Year Counter		1	2	3	4	5	6	7	8	9	10	11
Life Flag		1	1	1	1	1	1	1	1	1	1	1
Remaining Expense Flag	*** Need to change 2022 after testing	0	0	1	1	1	1	1	1	1	1	1

FINANCIAL IMPACT MODEL

Assumptions

Factor/Variable	Value
PreTax Rate of Return	8.612%
Property Tax Factor	2.452%
Insurance Factor	0.084%
Discount Rate	7.500%

	NPVRR Benefit	NPVRR Cost	B/C Ratio
Overall	10,539,979	14,555,021	-0.276
Remaining	13,238,207	11,409,169	0.160

COSTS

	NPV	Total	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CAPITAL + COR			0	3,400,000	3,447,664	673,584	0	0	0	0	0	0	0
CAPITAL + COR *Escalated*			0	3,464,600	3,579,920	712,712	0	0	0	0	0	0	0
Total Investment			0	3,464,600	7,044,520	7,757,232	7,757,232	7,757,232	7,757,232	7,757,232	7,757,232	7,757,232	7,757,232
Beginning Rate Base			0	3,464,600	6,698,060	6,723,076	5,971,421	5,219,766	4,468,110	3,716,455	2,964,800	2,213,145	1,461,489
Depreciation			0	(346,460)	(687,696)	(751,655)	(751,655)	(751,655)	(751,655)	(751,655)	(751,655)	(751,655)	(751,655)
Ending Rate Base			0	3,118,140	6,010,364	5,971,421	5,219,766	4,468,110	3,716,455	2,964,800	2,213,145	1,461,489	709,834
Average Rate Base			0	3,291,370	6,354,212	6,347,249	5,595,593	4,843,938	4,092,283	3,340,628	2,588,972	1,837,317	1,085,662
O&M			1,533,965	1,245,000	1,722,325	1,557,125	1,500,000	528,000	0	0	0	0	0
O&M *Escalated*			1,533,965	1,268,655	1,788,395	1,647,578	1,617,290	580,103	0	0	0	0	0
Other Costs			0	0	0	0	0	0	0	0	0	0	0
Other Costs *Escalated*			0	0	0	0	0	0	0	0	0	0	0
NPVRR OVERALL COSTS													
	NPV	**Total**											
Return Costs	$2,310,062	3,391,166	0	283,453	547,225	546,625	481,893	417,160	352,427	287,695	222,962	158,230	93,497
Depreciation Costs	$4,397,350	7,047,398	0	346,460	687,696	751,655	751,655	751,655	751,655	751,655	751,655	751,655	751,655
Property Tax	$1,109,362	1,779,342	0	84,952	172,732	190,207	190,207	190,207	190,207	190,207	190,207	190,207	190,207
Insurance	$37,778	60,593	0	2,893	5,882	6,477	6,477	6,477	6,477	6,477	6,477	6,477	6,477
O&M	$6,700,469	8,435,986	1,533,965	1,268,655	1,788,395	1,647,578	1,617,290	580,103	0	0	0	0	0
Other	$0	0	0	0	0	0	0	0	0	0	0	0	0
Total	$14,555,021	$20,714,487	$1,533,965	$1,986,413	$3,201,930	$3,142,543	$3,047,523	$1,945,603	$1,300,767	$1,236,035	$1,171,302	$1,106,570	$1,041,837
NPVRR REMAINING COSTS													
Return Costs	$2,064,781	3,107,714	0	0	547,225	546,625	481,893	417,160	352,427	287,695	222,962	158,230	93,497
Depreciation Costs	$4,097,546	6,700,938	0	0	687,696	751,655	751,655	751,655	751,655	751,655	751,655	751,655	751,655
Property Tax	$1,035,850	1,694,390	0	0	172,732	190,207	190,207	190,207	190,207	190,207	190,207	190,207	190,207
Insurance	$35,275	57,700	0	0	5,882	6,477	6,477	6,477	6,477	6,477	6,477	6,477	6,477
O&M	$4,175,717	5,633,366	0	0	1,788,395	1,647,578	1,617,290	580,103	0	0	0	0	0
Other	$0	0	0	0	0	0	0	0	0	0	0	0	0
Total	$11,409,169	$17,194,109	$0	$0	$3,201,930	$3,142,543	$3,047,523	$1,945,603	$1,300,767	$1,236,035	$1,171,302	$1,106,570	$1,041,837

BENEFITS			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CAPITAL + COR			0	0	0	0	0	0	0	0	0	0	0
CAPITAL + COR *Escalated*			0	0	0	0	0	0	0	0	0	0	0
Total Investment			0	0	0	0	0	0	0	0	0	0	0
Beginning Rate Base			0	0	0	0	0	0	0	0	0	0	0
Depreciation			0	0	0	0	0	0	0	0	0	0	0
Ending Rate Base			0	0	0	0	0	0	0	0	0	0	0
Average Rate Base			0	0	0	0	0	0	0	0	0	0	0
Total O&M			85,000	185,000	1,679,500	1,679,500	1,679,500	1,679,500	1,679,500	1,679,500	1,679,500	1,679,500	1,679,500
Total O&M *Escalated*			85,000	188,515	1,743,927	1,777,062	1,810,826	1,845,232	1,880,291	1,916,017	1,952,421	1,989,517	2,027,318
Other			0	0	0	0	0	0	0	0	0	0	0
Other *Escalated*			0	0	0	0	0	0	0	0	0	0	0
NPVRR OVERALL BENEFITS													
	NPV	**Total**											
Return	$0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	$0	0	0	0	0	0	0	0	0	0	0	0	0
Property Tax	$0	0	0	0	0	0	0	0	0	0	0	0	0
Insurance	$0	0	0	0	0	0	0	0	0	0	0	0	0
O&M	$10,539,979	17,216,126	85,000	188,515	1,743,927	1,777,062	1,810,826	1,845,232	1,880,291	1,916,017	1,952,421	1,989,517	2,027,318
Other	$0	0	0	0	0	0	0	0	0	0	0	0	0
Total	$10,539,979	$17,216,126	$85,000	$188,515	$1,743,927	$1,777,062	$1,810,826	$1,845,232	$1,880,291	$1,916,017	$1,952,421	$1,989,517	$2,027,318
NPVRR REMAINING BENEFITS													
Return	$0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	$0	0	0	0	0	0	0	0	0	0	0	0	0
Property Tax	$0	0	0	0	0	0	0	0	0	0	0	0	0
Insurance	$0	0	0	0	0	0	0	0	0	0	0	0	0
O&M	$10,539,979	17,216,126	85,000	188,515	1,743,927	1,777,062	1,810,826	1,845,232	1,880,291	1,916,017	1,952,421	1,989,517	2,027,318
Other	$0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Writeoff	$2,698,228	3,118,140	0	3,118,140	0	0	0	0	0	0	0	0	0
Total	$13,238,207	$20,334,266	$85,000	$3,306,655	$1,743,927	$1,777,062	$1,810,826	$1,845,232	$1,880,291	$1,916,017	$1,952,421	$1,989,517	$2,027,318

Question:

4. Refer to page 11, lines 16-23 of Ms. Anita Griffin's direct testimony. Please:
a. Provide the total company cost for this project by year from inception to completion and the portion applicable to the electric business.
b. Provide the project's current phase and a timeline of the remaining phases with start and completion dates.
c. Identify specifically what the $1.19 million will be spent on.
d. Provide the number of customers with multiple accounts and how many of them have asked for the proposed features the Company seeks to implement in the past three years.

Response:

A:

O&M

	2022	2023
ELECTRIC	$1,205,665.00	$191,955.00
Total	$1,799,500.00	$286,500.00

Capital		
	2022	2023
ELECTRIC	$6,298,000.00	$924,600.00
Total	$9,400,000.00	$1,380,000.00

B: The project has not yet been started.

Initiation	Project Planning and Scope Definition	Detailed Solution Design	Execution	Completion
1/10/2022	2/21/2022	4/18/2022	8/22/2022	3/20/2023

C: The $1.19 million will support Project Planning and Scope Definition activities which will include labor for Company resources and a third-party integrator. The nature of the project will require complex solutions to better align contract accounts associated with larger business customers. Resources will review the existing solution, the structure of data stored in the customer system of record, and solidifying milestones for the project.

D: Of the 183,542 business customers, 69,238 (38%) have multiple accounts. Consumers Energy does not track the number of customers that have provided this specific feedback. However, there are 19,736 customers receiving electronic bills from the complex billing vendor, all of whom would benefit from this project.

Anita J. Griffin
June 4, 2021

Customer Strategy Data & Analytics

Question:

5. Refer to page 12, lines 4-6 of Ms. Anita Griffin's direct testimony. Who is the third party that provides the portal and who pays for this portal or service?

Response:

The self-service customer portal is provided by the Company and is part of the current website functionality. The collective billing activities are provided by BillTrust and are paid for by the Company.

Anita J. Griffin
June 3, 2021

Question:

19. Refer to page 27, lines 1-6, and page 28, lines 1-7 of Ms. Anita Griffin's direct testimony. Please:
a. Provide the total company cost for this project by year from inception to completion and the portion applicable to the electric business.
b. Provide the current phase that the project is in and a timeline of the remaining phases with start and completion dates.
c. Identify specifically what the $1.66 million in O&M expense will be spent on.
d. Why is a bill redesign necessary?
e. What are the limitations?
f. Provide the annual reduction in internal costs and the year they begin.

Response:

A: Please see the attachment.

B: The project is currently in the investment planning phase.

Investment Planning	Project Plan and Scope Definition	Final Planning and Design	Execution	Completion
1/1/2022	2/24/2022	5/4/2022	11/16/2022	6/14/2023

C: The $1.66 Million will be spent in labor and associated overheads to deliver the project.

D: The Company last implemented a partial billing redesign at the end of 2015. The enterprise billing solution is outdated and limits bill presentation capability, driving customer defects, customer dissatisfaction, and operational inefficiencies. A redesign of all customer billing documents is necessary to capitalize on flexible capabilities that state-of-the-art systems now offer. A new, modular bill will allow for customized bill presentation for different rates and program enrollments and prioritized placement of information to unique account and customer characteristics. Among other things, new capabilities also include flexible messaging and on-bill communications (vs inserts) that cannot be executed today and will better accommodate complex billing conditions. The following items are opportunities which add value to the existing experience:

- Conversion from billing inserts to "onserts" to streamline customer experience, increase customer engagement, and reduce waste
- A redesign of all customer bills into a flexible format enhancing clarity and improving understanding of current rate programs
- Enabling opportunity for improved engagement with current future rate and product offerings
- Ability to provide expedited and customized on-bill messaging
- Ability to provide multiple bill languages
- Expansion of eBill delivery to multiple formats, interactive eBill experience, and video tutorials for complex bills
- An outsourced solution for bill printing and mailing to optimize costs and leverage scale to protect from future cost increases.

- Access to world-class interaction tools for CSRs to improve call experience and increase first call resolution for billing questions
- Ability to consolidate multiple mailings to reduce postage and improve customer mail experience

E: The current technology imposes the following limitations:

- Current platform requires a minimum of four weeks to customize a message on a bill
- Current platform requires months to correct printing waste with additional blank pages caused by formatting defects
- Current Bill Formats are absent of installment plan information.

F: Annual reductions:

- Postage - $950k/year – Expected to begin July 2023
- Call Reduction - $200K –– Realized over 12 months post implementation

Anita J. Griffin
June 4, 2021

Bill Design and Delivery Transformation Total Project							AG-CE-956
		Capital projected	**O&M projected**	**Capital projected**	**O&M projected**	**Capital projected**	**O&M projected**
		2022	**2022**	**2023**	**2023**	**Total**	**Total**
	Labor	4,745,000	2,300,000	3,300,000	1,300,000	8,045,000	3,600,000
	Contractor	2,400,000		1,500,000	1,500,000	3,900,000	1,500,000
	Non-Labor, Overheac	2,033,200	218,500	1,334,000	123,500	3,367,200	342,000
	Non-Labor Other	648,648		646,380		1,295,028	-
		9,826,848	**2,518,500**	**6,780,380**	**2,923,500**	**16,607,228**	**5,442,000**

Bill Design and Delivery Transformation Electric Portion							
		Capital projected	**O&M projected**	**Capital projected**	**O&M projected**	**Capital projected**	**O&M projected**
		2022	**2022**	**2023**	**2023**	**Total**	**Total**
	Labor	3,335,735	###########	2,319,900	858,000.00	5,655,635	2,376,000
	Contractor	1,687,200	-	1,054,500	990,000.00	2,741,700	990,000
	Non-Labor, Overheac	1,429,340	144,210.00	937,802	81,510.00	2,367,142	225,720
	Non-Labor Other	456,000	-	454,405	-	910,405	-
		6,908,274	**1,662,210**	**4,766,607**	**1,929,510**	**11,674,881**	**3,591,720**

Question:

20. Refer to page 28, lines 8-16 of Ms. Anita Griffin's direct testimony. Please provide the net present value cost/benefit analysis in Excel with formulas intact that economically justifies this project.

Response:

Please see the attached.

Anita J. Griffin
June 4, 2021

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030
Year Counter	1	2	3	4	5	6	7	8	9
Life Flag	1	1	1	1	1	1	1	1	1
Remaining Expense Flag	1	1	1	1	1	1	1	1	1

FINANCIAL IMPACT MODEL

Assumptions

Factor/Variable	Value
PreTax Rate of Return	8.612%
Property Tax Factor	2.452%
Insurance Factor	0.084%
Discount Rate	7.500%

	NPVRR Benefit	NPVRR Cost	B/C Ratio
Overall	7,072,393	25,297,533	-0.720
Remaining	7,072,393	25,297,533	-0.720

COSTS

	NPV	Total	2022	2023	2024	2025	2026	2027	2028	2029	2030
CAPITAL + COR			9,826,848	6,780,380	0	0	0	0	0	0	0
CAPITAL + COR *Escalated*			9,826,848	6,909,207	0	0	0	0	0	0	0
Total Investment			9,826,848	16,736,055	16,736,055	16,736,055	16,736,055	16,736,055	16,736,055	16,736,055	16,736,055
Beginning Rate Base			0	5,817,335	3,861,812	1,906,289	(49,233)	(2,004,756)	(3,960,279)	(5,915,802)	(7,871,325)
Depreciation			(1,091,872)	(1,955,523)	(1,955,523)	(1,955,523)	(1,955,523)	(1,955,523)	(1,955,523)	(1,955,523)	(1,955,523)
Ending Rate Base			(1,091,872)	3,861,812	1,906,289	(49,233)	(2,004,756)	(3,960,279)	(5,915,802)	(7,871,325)	(9,826,848)
Average Rate Base			(545,936)	4,839,574	2,884,051	928,528	(1,026,995)	(2,982,518)	(4,938,041)	(6,893,564)	(8,849,087)
O&M			2,518,500	2,923,500	2,200,000	2,200,000	2,200,000	2,200,000	0	0	0
O&M *Escalated*			2,518,500	2,979,047	2,284,394	2,327,798	2,372,026	2,417,094	0	0	0
Other Costs			0	0	0	0	0	0	0	0	0
Other Costs *Escalated*			0	0	0	0	0	0	0	0	0
NPVRR OVERALL COSTS											
	NPV	**Total**									
Return Costs	($638,003)	(1,428,213)	(47,016)	416,784	248,374	79,965	(88,445)	(256,854)	(425,264)	(593,674)	(762,083)
Depreciation Costs	$11,670,663	16,736,055	1,091,872	1,955,523	1,955,523	1,955,523	1,955,523	1,955,523	1,955,523	1,955,523	1,955,523
Property Tax	$2,460,097	3,523,899	240,954	410,368	410,368	410,368	410,368	410,368	410,368	410,368	410,368
Insurance	$83,776	120,002	8,205	13,975	13,975	13,975	13,975	13,975	13,975	13,975	13,975
O&M	$11,720,999	14,898,859	2,518,500	2,979,047	2,284,394	2,327,798	2,372,026	2,417,094	0	0	0
Other	$0	0	0	0	0	0	0	0	0	0	0
Total	$25,297,533	$33,850,602	$3,812,516	$5,775,696	$4,912,634	$4,787,628	$4,663,447	$4,540,105	$1,954,602	$1,786,192	$1,617,782
NPVRR REMAINING COSTS											
Return Costs	($638,003)	(1,428,213)	(47,016)	416,784	248,374	79,965	(88,445)	(256,854)	(425,264)	(593,674)	(762,083)
Depreciation Costs	$11,670,663	16,736,055	1,091,872	1,955,523	1,955,523	1,955,523	1,955,523	1,955,523	1,955,523	1,955,523	1,955,523
Property Tax	$2,460,097	3,523,899	240,954	410,368	410,368	410,368	410,368	410,368	410,368	410,368	410,368
Insurance	$83,776	120,002	8,205	13,975	13,975	13,975	13,975	13,975	13,975	13,975	13,975
O&M	$11,720,999	14,898,859	2,518,500	2,979,047	2,284,394	2,327,798	2,372,026	2,417,094	0	0	0
Other	$0	0	0	0	0	0	0	0	0	0	0
Total	$25,297,533	$33,850,602	$3,812,516	$5,775,696	$4,912,634	$4,787,628	$4,663,447	$4,540,105	$1,954,602	$1,786,192	$1,617,782

BENEFITS

	NPV	Total	2022	2023	2024	2025	2026	2027	2028	2029	2030
CAPITAL + COR			0	0	0	0	0	0	0	0	0
CAPITAL + COR *Escalated*			0	0	0	0	0	0	0	0	0
Total Investment			0	0	0	0	0	0	0	0	0
Beginning Rate Base			0	0	0	0	0	0	0	0	0
Depreciation			0	0	0	0	0	0	0	0	0
Ending Rate Base			0	0	0	0	0	0	0	0	0
Average Rate Base			0	0	0	0	0	0	0	0	0
Total O&M			0	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Total O&M *Escalated*			0	1,222,800	1,246,033	1,269,708	1,293,832	1,318,415	1,343,465	1,368,991	1,395,002
Other			0	0	0	0	0	0	0	0	0
Other *Escalated*			0	0	0	0	0	0	0	0	0
NPVRR OVERALL BENEFITS											
	NPV	**Total**									
Return	$0	0	0	0	0	0	0	0	0	0	0
Depreciation	$0	0	0	0	0	0	0	0	0	0	0
Property Tax	$0	0	0	0	0	0	0	0	0	0	0
Insurance	$0	0	0	0	0	0	0	0	0	0	0
O&M	$7,072,393	10,458,246	0	1,222,800	1,246,033	1,269,708	1,293,832	1,318,415	1,343,465	1,368,991	1,395,002
Other	$0	0	0	0	0	0	0	0	0	0	0
Total	$7,072,393	$10,458,246	$0	$1,222,800	$1,246,033	$1,269,708	$1,293,832	$1,318,415	$1,343,465	$1,368,991	$1,395,002
NPVRR REMAINING BENEFITS											
Return	$0	0	0	0	0	0	0	0	0	0	0
Depreciation	$0	0	0	0	0	0	0	0	0	0	0
Property Tax	$0	0	0	0	0	0	0	0	0	0	0
Insurance	$0	0	0	0	0	0	0	0	0	0	0
O&M	$7,072,393	10,458,246	0	1,222,800	1,246,033	1,269,708	1,293,832	1,318,415	1,343,465	1,368,991	1,395,002
Other	$0	0	0	0	0	0	0	0	0	0	0
Avoided Writeoff	$0	0	0	0	0	0	0	0	0	0	0
Total	$7,072,393	$10,458,246	$0	$1,222,800	$1,246,033	$1,269,708	$1,293,832	$1,318,415	$1,343,465	$1,368,991	$1,395,002

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

Question:

6. Refer to page 12, lines 9-19 of Ms. Anita Griffin's direct testimony. Please:
a. Provide the total company cost for this project by year from inception to completion and the portion applicable to the electric business.
b. Provide the current phase that the project is in and a timeline for the remaining phases with start and completion dates.
c. Provide the number of customers who have asked for the proposed mobile application the Company seeks to implement in the past three years.

Response:

A:

Total Costs Annually (in M):

2020	2021	2022	2023	2024	2025	2026
$4.317	$7.610	$3.544	$3.544	$3.544	$3.544	$3.544

The portion allocated to the electric business is 67%.

B: The project is currently within the execution phase where the application is being developed and tested in preparation for release to the public; the targeted completion date is September 2021.

C: In 2019, of 29,134 customers surveyed after live agent calls, 9,790 (33.6%) answered 'Yes' to the question 'If Consumers Energy offered a mobile app, would you use the app instead of placing a call?'

In 2020, of 22,116 customers surveyed after live agent calls, 7,799 (35.3%) answered 'Yes' to the question 'If Consumers Energy offered a mobile app, would you use the app instead of placing a call?'

This question was not asked on 2018 surveys.

Anita J. Griffin
June 3, 2021

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Question:

7. Refer to page 13, lines 9-21 of Ms. Anita Griffin's direct testimony. Please:
a. Explain why the Company cannot fix the login errors.
b. How many customers were surveyed and when? How many responded?
c. Provide a copy of the summary survey results and a copy of the questions asked.
d. Provide the analysis and calculations to arrive at the 300,000 customers.

Response:

a. The Company cannot solve all users' login problems with the website because biometric and other advanced technologies around login elimination are restricted to native app use. Websites do not have the ability to leverage Face ID, Touch ID or other methods in the same way that a mobile app is designed to use them.
b. 29,134 customers were surveyed and responded throughout 2019. 9,790 (33.6%) answered 'Yes' to the question 'If Consumers Energy offered a mobile app, would you use the app instead of placing a call?'
c. In 2019, of 29,134 customers surveyed after live agent calls, 9,790 (33.6%) answered 'Yes' to the question 'If Consumers Energy offered a mobile app, would you use the app instead of placing a call?'
d. The 300,000 Mobile App users number was based on guidance provided by Accenture. The Company is targeting an internal number of users that is slightly higher than that guidance, which reflects current expectations of customer interest and potential download rates. Consumers Energy will be tracking those enrollments once the app is launched.

Anita J. Griffin
June 3, 2021

Question:

8. Refer to page 14, lines 4-19 of Ms. Anita Griffin's direct testimony. With at least 300,000 customers using their mobile devices with the implementation of this project, please provide the expected cost savings and a copy of the net present value cost/benefit analysis in Excel with formulas intact showing this project is economically justified.

Response:

The requested analysis is provided as an attachment to this response. It should be noted that the purpose of this project is to make it possible for customers to access their account, usage data, program enrollment information and other critical content without needing to access a computer, for the reasons given on pages 12 and 13 of my direct testimony. Thus, this program provides an important customer benefit, especially given the implications for successful Clean Energy Plan deployment.

Anita J. Griffin
June 4, 2021

AG-CE-945									
Project Costs			2020	2021	2022	2023	2024	2025	2026
	O&M		**$395,000.00**	**$1,282,000.00**	**$1,282,520.00**	**$1,282,520.00**	**$1,282,520.00**	**$1,282,520.00**	**$1,282,520.00**
	Capital		**$3,922,000.00**	**$5,197,000.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Breakout Costs									
	O&M		**$395,000.00**	**$1,282,000.00**	**$1,282,520.00**	**$1,282,520.00**	**$1,282,520.00**	**$1,282,520.00**	**$1,282,520.00**
	Capital		**$3,922,000.00**	**$5,197,000.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Benefts		SEE COMMENT		$ 354,400.00	$ 741,380.00	$ 564,550.00	$ 448,920.00		

Year		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Year Counter		1	2	3	4	5	6	7
Life Flag		1	1	1	1	1	1	1
Remaining Expense Flag	*** Need to change 2022 after testing	0	0	1	1	1	1	1

FINANCIAL IMPACT MODEL

Assumptions

Factor/Variable	**Value**
PreTax Rate of Return	8.612%
Property Tax Factor	2.452%
Insurance Factor	0.084%
Discount Rate	7.500%

	NPVRR Benefit	**NPVRR Cost**	**B/C Ratio**
Overall	1,716,618	14,506,742	-0.882
Remaining	4,565,767	10,667,636	-0.572

COSTS

			2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CAPITAL + COR			3,922,000	5,197,000	0	0	0	0	0
CAPITAL + COR *Escalated*			3,922,000	5,295,743	0	0	0	0	0
Total Investment			3,922,000	9,217,743	9,217,743	9,217,743	9,217,743	9,217,743	9,217,743
Beginning Rate Base			0	4,735,457	3,292,548	1,849,638	406,729	(1,036,181)	(2,479,090)
Depreciation			(560,286)	(1,442,910)	(1,442,910)	(1,442,910)	(1,442,910)	(1,442,910)	(1,442,910)
Ending Rate Base			(560,286)	3,292,548	1,849,638	406,729	(1,036,181)	(2,479,090)	(3,922,000)
Average Rate Base			(280,143)	4,014,003	2,571,093	1,128,183	(314,726)	(1,757,636)	(3,200,545)
O&M			395,000	1,282,000	1,282,520	1,282,520	1,282,520	1,282,520	1,282,520
O&M *Escalated*			395,000	1,306,358	1,331,719	1,357,021	1,382,805	1,409,078	1,435,851
Other Costs			0	0	0	0	0	0	0
Other Costs *Escalated*			0	0	0	0	0	0	0
NPVRR OVERALL COSTS									
	NPV	**Total**							
Return Costs	$244,582	186,039	(24,126)	345,686	221,423	97,159	(27,104)	(151,368)	(275,631)
Depreciation Costs	$6,821,471	9,217,743	560,286	1,442,910	1,442,910	1,442,910	1,442,910	1,442,910	1,442,910
Property Tax	$1,076,341	1,452,282	96,167	226,019	226,019	226,019	226,019	226,019	226,019
Insurance	$36,654	49,456	3,275	7,697	7,697	7,697	7,697	7,697	7,697
O&M	$6,327,694	8,617,832	395,000	1,306,358	1,331,719	1,357,021	1,382,805	1,409,078	1,435,851
Other	$0	0	0	0	0	0	0	0	0
Total	$14,506,742	$19,523,351	$1,030,602	$3,328,669	$3,229,767	$3,130,806	$3,032,326	$2,934,336	$2,836,845
NPVRR REMAINING COSTS									
Return Costs	($32,109)	(135,521)	0	0	221,423	97,159	(27,104)	(151,368)	(275,631)
Depreciation Costs	$5,051,678	7,214,548	0	0	1,442,910	1,442,910	1,442,910	1,442,910	1,442,910
Property Tax	$791,301	1,130,095	0	0	226,019	226,019	226,019	226,019	226,019
Insurance	$26,947	38,484	0	0	7,697	7,697	7,697	7,697	7,697
O&M	$4,829,818	6,916,474	0	0	1,331,719	1,357,021	1,382,805	1,409,078	1,435,851
Other	$0	0	0	0	0	0	0	0	0
Total	$10,667,636	$15,164,080	$0	$0	$3,229,767	$3,130,806	$3,032,326	$2,934,336	$2,836,845

BENEFITS

			2020	2021	2022	2023	2024	2025	2026
CAPITAL + COR			0	0	0	0	0	0	0
CAPITAL + COR *Escalated*			0	0	0	0	0	0	0
Total Investment			0	0	0	0	0	0	0
Beginning Rate Base			0	0	0	0	0	0	0
Depreciation			0	0	0	0	0	0	0
Ending Rate Base			0	0	0	0	0	0	0
Average Rate Base			0	0	0	0	0	0	0
Total O&M			0	354,400	741,380	564,550	448,920	0	0
Total O&M *Escalated*			0	361,134	769,820	597,345	484,023	0	0
Other			0	0	0	0	0	0	0
Other *Escalated*			0	0	0	0	0	0	0
NPVRR OVERALL BENEFITS									
	NPV	**Total**							
Return	$0	0	0	0	0	0	0	0	0
Depreciation	$0	0	0	0	0	0	0	0	0
Property Tax	$0	0	0	0	0	0	0	0	0
Insurance	$0	0	0	0	0	0	0	0	0
O&M	$1,716,618	2,212,321	0	361,134	769,820	597,345	484,023	0	0
Other	$0	0	0	0	0	0	0	0	0
Total	$1,716,618	$2,212,321	$0	$361,134	$769,820	$597,345	$484,023	$0	$0
NPVRR REMAINING BENEFITS									
Return	$0	0	0	0	0	0	0	0	0
Depreciation	$0	0	0	0	0	0	0	0	0
Property Tax	$0	0	0	0	0	0	0	0	0
Insurance	$0	0	0	0	0	0	0	0	0
O&M	$1,716,618	2,212,321	0	361,134	769,820	597,345	484,023	0	0
Other	$0	0	0	0	0	0	0	0	0
Avoided Writeoff	$2,849,149	3,292,548	0	3,292,548	0	0	0	0	0
Total	$4,565,767	$5,504,869	$0	$3,653,681	$769,820	$597,345	$484,023	$0	$0

Question:

24. Refer to page 33, lines 1-16 of Ms. Anita Griffin's direct testimony. Please:

a. Provide the total company cost for this project by year from inception to completion and the portion applicable to the electric business.

b. Provide the current phase that the project is in and a timeline of the remaining phases with start and completion dates.

c. Identify specifically what the $2.2 million in O&M expense will be spent on.

d. How many potential users does the Company expect and on what basis?

e. Provide the cost savings or other financial benefits expected from offering these alternative payment options.

f. Provide the net present value cost/benefit analysis in Excel with formulas intact that economically justifies this project.

Response:

A:

Customer Loyalty Project

	2022
O&M	**4,000,000.00**
Elec	2,040,000.00
Gas	1,960,000.00
Capital	**4,000,000.00**
Elec	2,000,000.00
Gas	2,000,000.00

Alternative Payment Rollout

	2022
O&M	**392,156.86**
Elec	200,000.00
Gas	192,156.86
Capital	**980,392.16**
Elec	500,000.00
Gas	480,392.16

B:

The Customer Loyalty Project has not started.

Initiation	Project Plan and Scope Definition	Final Plan and Design	Execution	Go-Live
1/15/2022	2/7/2022	3/7/2022	4/15/2022	7/15/2022

Alternative Payment Pilot

Initiation	Project Plan and Scope Definition	Final Plan and Design	Execution	Go-Live
8/2/21	8/23/21	9/23/21	10/14/21	12/6/21

Alternative Payment Rollout

Initiation	Project Plan and Scope Definition	Final Plan and Design	Execution	Go-Live
3/7/22	4/5/22	5/2/22	6/1/22	8/15/22

C:

Customer Loyalty Program	12 Mos Ending Dec 31 2022 Projected
Labor	$150,000
Material	$1,500,000
Contractor	$250,000
Non-Labor Overhead	$100,000
Non-Labor Other	
Total	$2,000,000
Alternative Payment Program	
Non-Labor Other	$200,000
Total	$200,000

D:

Regarding the Customer Loyalty Program: The Company estimates that 3-4% of customers will participate in the first year of the program, however participation will be greatly influenced by the extent of communication and value of incentives that are provided. These parameters will be tested prior to launch to help optimize results and value, as certain offers will likely have greater appeal to some customers than others.

Alternative Payment options anticipates 50,000 customers to utilize the platform by December 2022. Current forecasts identify customers begin to use the platform in December 2021 with a 2% ramp up per month

E:

The Company has not completed a formal cost/benefit analysis at this point. It is expected to be complete once the pilot has been approved and is in the planning and design phase.

F:

See response to part E.

Anita J. Griffin
June 4, 2021

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

Question:

12. Refer to page 17, lines 8-11 of Ms. Anita Griffin's direct testimony. Please:
a. Provide the total company cost for this project by year from inception to completion and the portion applicable to the electric business.
b. Provide the current phase that the project is in and a timeline of the remaining phases with start and completion dates.
c. Identify specifically what the $313,000 will be spent on.

Response:

a. Following are the projected total company and electric business costs for the Flexible and Advanced Payment Options project by year from inception to completion.

	Total Company		Electric	
	Capital	O&M	Capital	O&M
2022	$ 2.15	$ 0.47	$ 1.51	$ 0.31

b. This project is currently in the investment planning stage to determine the business requirements and possible technology options.

The timeline of the remaining phases for the Flexible and Advanced Payment Options project is as follows. A phase starts immediately upon completion of the preceding phase.

Investment Planning Stage Completion – 3/2/2022
Plan Phase Completion – 3/9/2022
Define Phase Completion – 4/11/2022
Execution Phase Completion – 6/20/2022
Go-Live Completion – 9/26/2022
Close Phase Completion – 10/26/2022

c. The $313,000 will be spent on project activities that must adhere to FASB ASC 350-40 guideline for Internal Use Software. These project activities are expensed during the project plan and project close phases. For this project, the $313,000 also includes performing impact assessments on the Company's existing systems including SAP, the Interactive Voice Response, and web platforms.

Jeffrey D Tolonen

Jeffrey D. Tolonen
June 4, 2021

Question:

13. Refer to Exhibit A-110 (JDT-9).

a. For ARP-Collaboration on page 1, please explain the reasons for the increase in capital expenditures in 2021 and 2022 over the prior two years.
b. For ARP-OT Storage on page 4, please explain why no capital expenditures were allocated to the electric business in 2019.
c. For ARP-OT Support on page 5, please explain the reasons for the increase in capital expenditures in 2021 and 2022 over the prior two years.
d. For ARP-Printer Asset Management on page 6, please explain the reasons for the increase in capital expenditures in 2021 over the prior two years.
e. For ARP-Workstation Asset Management. on page 9, please explain the reasons for the increase in capital expenditures in 2021 and 2022 over the prior two years.

Response:

a. The increase in ARP-Collaboration capital expenditure in 2021 and 2022 is due to the transition from a decentralized physical telephone private branch exchange (PBX) system to a centralized PBX system. The manufacturer ended the development of the current platform in 2014 and hardware parts are no longer being manufactured. The implementation of a centralized system increases the initial costs to replace but reduces the ongoing cost to maintain individual PBX systems at various Company locations.

b. No storage arrays required refreshing in 2019, therefore, no capital expenditures were allocated to the electric business in 2019 for the Asset Refresh Project category - ARP-OT Storage Area Network (SAN).

c. The increase in ARP-OT Support Electric capital expenditures in 2021 and 2022 over the prior two years is due to the combination of replacing existing aging assets and adequately supporting new assets from investment growth in this area.

d. The increase in ARP-Printer Asset Management capital expenditures in 2021 over the prior two years is due to the five-year refresh cycle for these assets. Five years ago, there was a significant number of replacements when the technology to support more secure printing was implemented. These assets are now due for replacement.

e. The increase in ARP-Workstation Asset Management capital expenditures in 2021 and 2022 over the prior years is due to increases in scheduled replacements per refresh cycle, previous year deferrals for equipment replacements, and incremental unit cost increases.

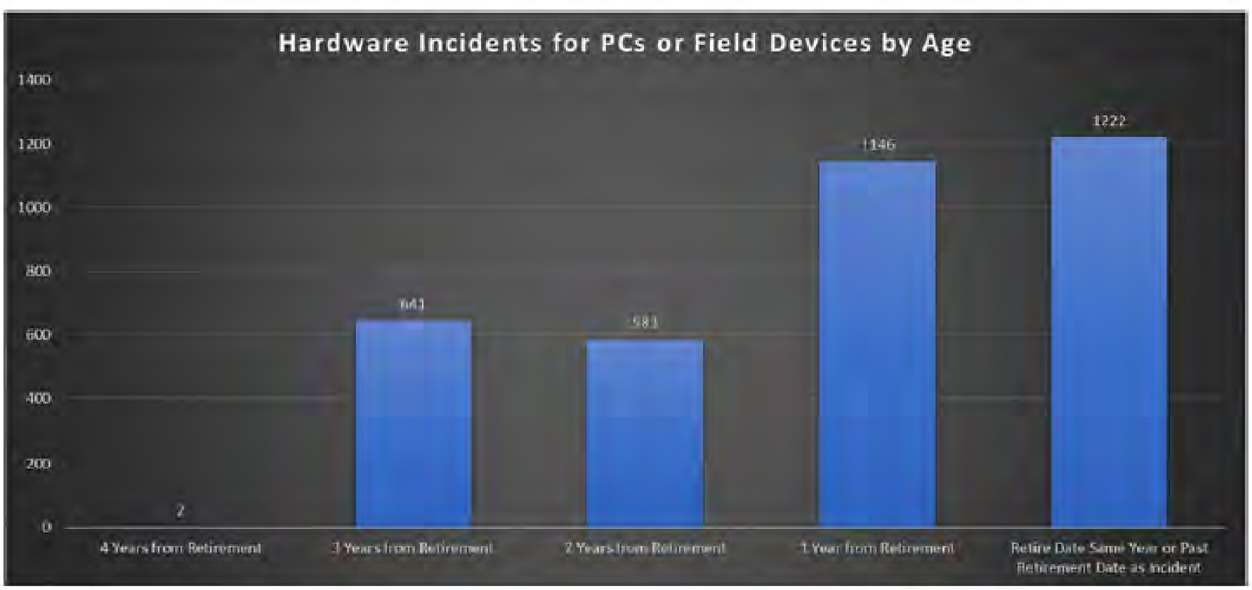
Jeffrey D. Tolonen
June 2, 2021

Question:

4. Refer to page 55, lines 28-42 of Mr. Tolonen's direct testimony. Please explain why a 4-year cycle is necessary and not a longer 5 to 7-year cycle. What evidence does the Company have that a 4-year cycle is necessary?

Response:

A four-year refresh cycle is necessary for the ARP – Workstation Asset Management project due to the critical role these devices play in supporting customer interactions and business operations. As workstation assets age, the number of incidents or problems with the assets increase as shown in the graph below which depicts incident counts for assets over time. Incident counts reflect lost productivity and expense to repair or replace the assets. For further documentation and justification for a 4-year refresh cycle, please refer to my direct testimony, page 49, lines 21 – 23, for reference to the Michigan Department of Technology, Management & Budget's IT Lifecycle Report. The agency currently recommends a four-year refresh cycle for this asset class for reasons described within. The Company continues to follow the guidance of government and industry experts for workstation asset refresh cycles and will adjust these cycles as appropriate.



Jeffrey D. Tolonen
June 2, 2021

U20963-AG-CE-890
Page **1** of **1**

Question:

7. Refer to page 85, lines 9-42 of Mr. Tolonen's direct testimony. The Digital-Hybrid Cloud and Data Center Migration seems to be directed at increasing efficiency, reducing costs, and otherwise improving operations. Please provide a copy of the net present value cost/benefit analysis in Excel with formulas intact and supporting data showing the project is economically justified.

Response:

The cost/benefit ratio for the Digital-Hybrid Cloud and Data Center Migration project is .18. The cost/benefit ratio is calculated by our internal Business Planning System using the following formula:

$$\textit{Financial Value } (F) = \frac{\sum B + x}{(\sum C_T - \sum C_{ATD})} - 1$$

Where
B = Financial Benefits
C_T = Total Costs
C_{ATD} = Actual To Date Costs
x = Avoided Write-off

Since the cost/benefit analysis is calculated by our internal Business Planning System, it is not available in Excel with formulas.

Jeffrey D. Tolonen
June 2, 2021

Question:

21. Refer to page 14, lines 18-43 of Ms. Gaston's direct testimony. Please:

a. Explain why the Core Human Capital needs to be transformed and how the technology system will achieve that transformation.
b. Identify what specifically the $1,592,748 will be spent on and in which year.

Response:

a. The Core HCM needs to be transformed because the current core HR technology platform and infrastructure cannot deliver the functionality and technical capability demanded by the continuously changing and progressing HR and Utility industries. Recent market and environmental factors and circumstances have further increased the criticality of technology capability to successfully operate the business in service of our coworkers and customers. Additionally, core HR data and processes are amongst the most wide-spread and impactful across the company.

As core HR data is contained and maintained today, it

- Has a high cost and time requirement for even basic enhancements, including those necessary for compliance purposes;
- Does not have the technical structure to accommodate new employee, job and organizational data required to support HR's transformation to best-in-class HR and Talent programs and processes (the current structure is based on the 2008 implementation requirements);
- Increases the costs and time required to implement new technologies that require integration with SAP HCM due to the need for custom integration development; and
- Cannot deliver easy automation for assigning tasks, training, access, etc. due to the integration and data structure limitations.

The new technology system will address these limitations of the existing system and provide:

- A solution to collect and maintain core HR data in a standard, best in class structure
- More efficient, cost effective and timely ongoing maintenance;
- Quicker and lower cost enhancements in support of changing business, HR and compliance requirements;
- The infrastructure to facilitate low cost integration between the core HR data system and other technologies across the business; and
- An intuitive user interface to complete transactional and operational tasks for updating, changing and adding core HR data.

Examples of current limitations that will be transformed with the new technology include:

1. Automation of security access using **role-based permissions**: Permissions are currently maintained and granted manually on an individual basis. With the transformation of core HR data, the Company will be able to automate access based on an employee's role using job function and job family data that currently, is not available in SAP HCM. As employees change roles, transfer between

departments, are promoted or leave the Company, role-based access will automate the proper access changes minimizing work delays and disruptions while enhancing security.

2. Automation of **training assignments** (including safety, compliance and company policy acknowledgements): Training assignments are currently manually assigned to employees. With the transformation of core HR data, the Company will be able to automate training assignments based on an employee's job title, job family and other core HR data.

b. Please see Company witness Jeffrey D. Tolonen's response.

Karen M. Gaston
May 28, 2021

Budget, Planning & Analysis

U20963-AG-CE-862 (Partial)
Page **1** of **1**

Question:

21. Refer to page 14, lines 18-43 of Ms. Gaston's direct testimony. Please:

a. Explain why the Core Human Capital needs to be transformed and how the technology system will achieve that transformation.

b. Identify what specifically the $1,592,748 will be spent on and in which year.

Response:

a. Please see Company witness Gaston's response.

b. Please see table below for categorical spend breakdown of $1,592,748 for Core Human Capital Management Transformation project. The Company plans to spend this amount in 2022.

Cost Category	2022
Labor	$632,880
Contractor	$703,200
Overhead & Other	$256,668
Total	**$1,592,748**

Jeffrey D. Tolonen

Jeffrey D. Tolonen
May 28, 2021

Information Technology

U20963-SA-CE-252 (Partial - Gaston)
Requested By: Lauren Fromm (LF-5)
Respondent: Karen M. Gaston
Date of Response: April 28, 2021
Page **1** of **1**

Question:

6. Regarding the Integrated Business Planning, Forecasting, Resource Planning, and Managerial Reporting project:
a. What are the expected O&M savings that will result from the elimination of waste, and duplication of effort and introduction of standardized and automated reporting as stated in the project synopsis? When are these savings expected to begin accruing?
b. Has the Company chosen between an on-premise or cloud software tool yet?
c. Has the Company issued the RFP for this project? If not, when will the RFP be issued?

Response:

a. The annual anticipated savings is $1.6M which includes hard savings of $1.0M (of which $0.6M is O&M + $0.4M is Capital) and soft savings of $0.6M. These savings will be realized in organizations throughout the Company and are expected to be realized beginning in 2025 which is the year after completion of the project.

U20963-SA-CE-252 (Partial – Tolonen)
Requested By: Lauren Fromm (LF-5)
Respondent: Jeffrey D. Tolonen
Date of Response: April 28, 2021
Page **1** of **1**

Question:

6. Regarding the Integrated Business Planning, Forecasting, Resource Planning, and Managerial Reporting project:

a. What are the expected O&M savings that will result from the elimination of waste, and duplication of effort and introduction of standardized and automated reporting as stated in the project synopsis? When are these savings expected to begin accruing?

b. Has the Company chosen between an on-premise or cloud software tool yet?

c. Has the Company issued the RFP for this project? If not, when will the RFP be issued?

Response:

a. Please refer to Company Witness Gaston's response.
b. The Company has not chosen between an on-premise or cloud software tool.
c. The Company has not issued an RFP for this project. The Company has issued a Request for Information (RFI) to inform estimates. The Company plans to issue an RFP in 2022.

Question:

28. Refer to Exhibit A-12 (JDT-6) Schedule B-5.3. Please provide the following information in Excel:

a. Expand this schedule to provide actual amounts for 2020.
b. Provide the actual expenditures for each year 2016-2018 at the summary line level.

Response:

a. Please see U20963-AG-CE-589-Tolonen_ATT 1 for revised Exhibit A-12 (JDT-6) Schedule B-5.3 with 2020 actual amounts.

b. Please see U20963-AG-CE-589-Tolonen_ATT 2 for the 2016-2018 actual capital expenditures at the summary line level.

Jeffrey D. Tolonen

Jeffrey D. Tolonen
May 7, 2021

Information Technology

MICHIGAN PUBLIC SERVICE COMMISSION						Case No.:	U-20963
Consumers Energy Company						Exhibit No.:	A-12 (JDT-6)
Projected Capital Expenditures						Schedule:	B-5.3
Information Technology						Page:	1 of 1
Summary of Actual and Projected Electric Capital Expenditures						Witness:	JDTolonen
For Years 2019 Through 2021 and Test Year 2022						Date:	May 2021
($000)							

Line No.	Description (a)	Historical 12 Mos Ended 12/31/2019 (b)	Actual 12 Mos Ended 12/31/2020 (c)	Projected Bridge Year 12 Mos Ending 12/31/2021 (d)	Projected Bridge Year 24 Mos Ending 12/31/2021 (e)	Projected Test Year 12 Mos Ending 12/31/2022 (f)
1	**Upgrades & Replacements (Enterprise)**	**$ 11,005**	**$ 642**	**$ 2,115**	**$ 2,757**	**$ 1,054**
	Software	308	139	-	139	-
	Materials	4,017	(52)	387	335	105
	Labor	1,024	204	1,039	1,242	363
	Contractor Costs	4,985	230	105	336	348
	Engineering	-	-	-	-	-
	Overhead & Others	670	122	584	706	237
	Contingency	-	-	-	-	-
2	**Upgrades & Replacements (Business Partner)**	**$ 1,565**	**$ 4,545**	**$ 3,183**	**$ 7,727**	**$ 3,973**
	Software	-	695	334	1,029	366
	Materials	1	443	391	834	104
	Labor	466	935	1,012	1,947	1,589
	Contractor Costs	766	1,485	827	2,312	1,054
	Engineering	-	-	-	-	-
	Overhead & Others	332	987	619	1,606	859
	Contingency	-	-	-	-	-
3	**Security**	**$ 5,217**	**$ 4,049**	**$ 4,786**	**$ 8,834**	**$ 5,669**
	Software	284	822	567	1,389	1,465
	Materials	1,837	924	2,172	3,096	2,826
	Labor	411	664	862	1,525	826
	Contractor Costs	2,483	1,200	743	1,942	387
	Engineering	-	-	-	-	-
	Overhead & Others	201	440	442	882	163
	Contingency	-	-	-	-	-
4	**IT Service Delivery**	**$ 13,773**	**$ 21,222**	**$ 23,922**	**$ 45,144**	**$ 26,809**
	Software	864	3,334	549	3,883	2,813
	Materials	10,106	15,682	17,213	32,894	17,101
	Labor	1,145	759	1,759	2,518	2,335
	Contractor Costs	1,039	1,092	3,470	4,562	2,039
	Engineering	-	-	-	-	-
	Overhead & Others	618	355	931	1,286	2,521
	Contingency	-	-	-	-	-
5	**Enhancements**	**$ 4,246**	**$ 3,884**	**$ 3,904**	**$ 7,788**	**$ 4,179**
	Software	66	110	-	110	-
	Materials	114	57	-	57	-
	Labor	1,122	1,374	2,976	4,350	3,117
	Contractor Costs	2,158	1,724	88	1,812	158
	Engineering	-	-	-	-	-
	Overhead & Others	786	619	840	1,459	904
	Contingency	-	-	-	-	-
6	**BP Functionality**	**$ 16,741**	**$ 15,646**	**$ 20,732**	**$ 36,379**	**$ 35,525**
	Software	268	8,694	2,050	10,744	3,780
	Materials	3,460	(3,515)	2,239	(1,276)	818
	Labor	1,677	1,961	6,956	8,916	11,344
	Contractor Costs	9,560	6,815	6,157	12,972	12,788
	Engineering	-	-	-	-	-
	Overhead & Others	1,776	1,691	3,331	5,022	6,795
	Contingency	-	-	-	-	-
7	**Architecture**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Software	-	-	-	-	-
	Materials	-	-	-	-	-
	Labor	-	-	-	-	-
	Contractor Costs	-	-	-	-	-
	Engineering	-	-	-	-	-
	Overhead & Others	-	-	-	-	-
	Contingency	-	-	-	-	-
	Total Capital	**$ 52,547**	**$ 49,988**	**$ 58,640**	**$ 108,629**	**$ 77,209**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Exhibit AG-1.32
Case No. U-20963
June 22, 2021

Adjustments to Capital Expenditures, Rate Base and Depreciation Expense

($000)

Line	Description (a)	Capital Expenditures[1] 2020 (b)	2021 (c)	2022 (d)	Total (e)	Rate Base Reduction (f)	Depreciation Rate[2] (g)	Reduction in Depreciation Expense (h)
1	**Contingency Costs**		$ 8,577	$ 18,689	$ 27,266	$ 17,922	4.94%	$ 885
2	**Distribution Plant:**							
3	LVD Lines New Business		6,267	9,963	16,230	11,249	3.05%	343
4	HVD Strategic Customers-New Business		8,480	1,023	9,503	8,992	3.05%	274
5	LVD Lines Demand Failures		10,794	10,977	21,771	16,283	3.05%	497
6	Streetlights SOAR Project		3,300		3,300	3,300	3.05%	101
7	LVD Asset Relocations		15,325	18,213	33,538	24,432	3.05%	745
8	LVD Lines Reliability		2,330	6,768	9,098	5,714	3.05%	174
9	HVD Lines Reliability		30,551	44,413	74,964	52,758	3.05%	1,609
10	Grid Modernization		20,619	36,340	56,959	38,789	3.05%	1,183
11	Metro Reliability		2,061	1,917	3,978	3,020	3.05%	92
12	HVD Line & Substation Rehab		4,685	23,000	27,685	16,185	3.05%	494
13	LVD Substation Rehab		4,465	3,265	7,730	6,098	3.05%	186
14	LVD Line Rehab		9,589	26,541	36,130	22,860	3.05%	697
15	Truck Tools and Other Tools		5,189	5,198	10,387	7,788	3.05%	238
16	System Control Projects		5,703	3,929	9,632	7,668	3.05%	234
17	**Power Generation**							
18	Hardy Spillway Remediation		7,700	19,250	26,950	17,325	17.88%	3,098
19	2020 Solar Projects Bid Event		13,936	114,002	127,938	70,937	4.35%	3,086
20	Hydro Units		12,920	22,893	35,813	24,367	17.88%	4,357
21	Construction Overhead Adjustment		3,000		3,000	3,000	4.35%	131
22	Actual 2020 Cap Ex under Forecast	$ 5,203			5,203	5,203	4.94%	257
23	**Information Technology**							
24	CRM System	1,841	1,734	1,758	5,333	4,454	20.00%	891
25	C&I Account Management System			6,610	6,610	3,305	20.00%	661
26	Bill Design & Delivery Transformation			6,910	6,910	3,455	20.00%	691
27	Customer Self-Service Mobile App	2,892	5,098	2,374	10,364	9,177	20.00%	1,835
28	Customer Loyalty & Alt. Payment Methods			2,500	2,500	1,250	20.00%	250
29	ARP-Workstation Asset Refresh		2,030	3,494	5,524	3,777	20.00%	755
30	Digital-Hybrid Cloud & Data Center			3,213	3,213	1,607	20.00%	321
31	Business Planning Optimization			352	352	176	20.00%	35
32	Core Human Capital Management			1,593	1,593	797	20.00%	159
33	Integrated Business Planning & Reporting			3,647	3,647	1,824	20.00%	365
34	Actual 2020 Cap Ex under Forecast	1,520			1,520	1,520	20.00%	304
35	**Operations Support**							
36	Customer Service Centers		3,830	34,775	38,605	21,218	1.49%	316
37	Marshall Training Center			3,125	3,125	1,563	1.49%	23
38	Unified Control Center		840	24,162	25,002	12,921	1.49%	193
39	Return to Work Project		4,025	5,677	9,702	6,864	1.49%	102
40	Actual 2019 Cap Ex under Forecast	5,050			5,050	5,050	1.49%	75
41	**Fleet Services**	-	34,826	20,500	55,326	45,076	10.73%	4,837
42	**Total**	$ 16,506	$ 227,874	$ 487,071	$ 731,451	$ 487,916		$ 30,494
43								
44	**Total Rate Base Reduction**					**$ 487,916**		

Source: (1) AG witness Coppola Direct Testimony and Exhibits.
(3) Depreciation rates from Company workpaper WP-JRC-36. Contingency depreciation rate is for Production (Steam).

MICHIGAN PUBLIC SERVICE COMMISSION **Exhibit AG-1.33**
Consumers Energy Company - Electric Rate Case **Case No. U-20963**
June 22, 2021
Recommended Capital Structure & Cost Rates for **Page 1 of 1**
Projected Year Ending December 2022 (Millions of Dollars)

Line	Description (a)	Note	Capital Balances (b)	% Permanent Capital (c)	% Total Capital (d)	Cost Rate* (e)	Total Cost (d) x (e) (f)	Conversion Factors* (g)	Pre-Tax Wtd. Cost (f) x (g) (h)
1	Long Term Debt	(A)	$ 9,452.0	49.80%	40.99%	3.55%	1.46%	1.0000	1.46%
2	Preferred Stock	(A)	37.0	0.19%	0.16%	4.50%	0.01%	1.3391	0.01%
3	Common Equity	(A)	9,490.0	50.00%	41.15%	9.50%	3.91%	1.3391	5.24%
4	Total Permanent Capital	(A)	18,979.0	100.00%	82.30%		5.37%		6.70%
5	Short Term Debt	(B)	200.0		0.87%	1.15%	0.01%	1.0000	0.01%
6	Deferred Income Taxes	(B)	3,751.0		16.27%	0.00%	0.00%	1.0000	0.00%
7	JDITC								
8	Long Term Debt		65.0		0.28%	3.55%	0.01%	1.0000	0.01%
9	Preferred Stock		-		0.00%	4.50%	0.00%	1.3391	0.00%
10	Common Equity		65.0		0.28%	9.50%	0.03%	1.3391	0.04%
11	Total JDITC	(B)	130.0						
12	**Total Capitalization & Cost Rates**		$ 23,060.0		100.00%		5.42%		6.76%

Notes
(A) Total per Company Exhibit A-14 (MRB-1) Schedule D-1, with 50% of total allocated to Common Equity and 50% allocated to preferred stock and long term debt.
(B) Per Company Exhibit A-14 (MRB-1) Schedule D-1
* All Cost Rates and Conversion Factors based on the Company case except for the Cost of Common Equity (see Exhibit AG-X2)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company - Electric Rate Case

Exhibit AG-1.34
Case No. U-20963
June 22, 2021

Summary of Cost of Common Equity Analysis

Line	Description (a)	Relative Weighting (b)	Proxy Rates (c)	Note (d)
1	Discounted Cash Flow Approach (DCF)	50.00%	9.32%	1
2	Capital Asset Pricing Model Approach (CAPM)	25.00%	8.79%	2
3	Utility Equity Risk Premium Approach	25.00%	8.82%	3
4	**Weighted Average Cost of Common Equity (Sum of Col. (b) x (c) for Lines 1, 2 and 3)**		**9.06%**	
5	Allowance for Other Risk Factors		0.44%	4
6	**Cost of Common Equity for Rate Case Purposes**		***9.50%***	

Note 1 See Exhibit AG-1.35
Note 2 See Exhibit AG-1.36
Note 3 See Exhibit AG-1.37
Note 4 The projected test year ending December 2021 assumes an increase in 30 Year U.S. Treasury Rates of 25 to 50 basis points (vs. Jun. 2020). The extent to which this increase is now reflected in the DCF results cannot be determined. If such increase in U.S. Treasury rates occurs, then the results could reflect an increase in the DCF cost of equity which is indicated in this higher cost. Additionally, the Company's service area may pose certain higher risks not present with peer utilities.

MICHIGAN PUBLIC SERVICE COMMISSION | **Exhibit AG-1.35**
Consumers Energy Company - Electric Rate Case | **Case No. U-20963**
June 22, 2021
Page 1 of 1

Discounted Cash Flow (DCF) Application
(See Equation Below)

Line	Company	Ticker	Average 30 Day High Low Price*	Avg. 2021 & 2022 Ann. Dividend**	Dividend Yield Col. (d)/c	EPS Growth Rate*** Value Line	EPS Growth Rate*** Analysts p/Yahoo	EPS Growth Rate*** Average of Col. (f) & (g)	DCF ROE for Each Co. Col. (e) + (h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Proxy Group								
1	Alliant Energy	LNT	$ 54.93	$ 1.56	2.84%	5.64%	5.50%	5.57%	8.41%
2	Ameren	AEE	81.58	2.10	2.57%	6.30%	7.70%	7.00%	9.57%
3	American Electric Power	AEP	84.24	2.92	3.47%	6.30%	6.20%	6.25%	9.72%
4	Consolidated Edison	ED	75.46	3.08	4.08%	5.91%	2.95%	4.43%	8.51%
5	Evergy	EVRG	63.04	2.11	3.35%	9.10%	5.80%	7.45%	10.80%
6	Pinnacle West Capital	PNW	85.00	3.33	3.92%	5.94%	3.50%	4.72%	8.64%
7	Portland General Electric	POR	49.73	1.65	3.32%	N/M	7.10%	7.10%	10.42%
8	WEC Energy	WEC	96.29	2.62	2.72%	6.73%	6.19%	6.46%	9.18%
9	Xcel Energy	XEL	71.15	1.78	2.50%	6.09%	6.20%	6.15%	8.65%
9	Average				***3.20%***	***6.50%***	***5.68%***	***6.13%***	$\boxed{\textit{9.32\%}}$
10	High								10.80%
11	Low								8.41%

* Average of High and Low prices per Yahoo from April 19, 2021 to May 28, 2021
** Average of Value Line Projected Dividends for 2020 and 2021 published March 12, April 23 and May 14, 2021 for proxy companies.
*** For Columns (f) and (g) per workpapers
N/M Value Line Growth for Portland General Electric over 15%.

__Equation__ **R = D/P + g** *Where*
R = the required return on the equity security
P = the current price of the equity security
D = the next dividend on the security
g = the expected growth rate of earnings

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company - Electric Rate Case

Capital Asset Pricing Model Application
(See Equation Below)

Line	Company & Ticker		% Common Equity	Current Beta (B)	Risk Premium (R_p)	Beta x Risk Premium Col. (c) x (d)	2022 Risk Free Rate (R_f)	K_e or 2022 CAPM ROE for Each Co. Cols. (e) + (f)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)
	Proxy Group							
1	Alliant Energy	LNT	45.5%	0.85	7.25%	6.16%	2.75%	8.91%
2	Ameren	AEE	44.1%	0.80	7.25%	5.80%	2.75%	8.55%
3	American Electric Power	AEP	40.4%	0.75	7.25%	5.44%	2.75%	8.19%
4	Consolidated Edison	ED	45.9%	0.75	7.25%	5.44%	2.75%	8.19%
5	Evergy	EVRG	47.8%	0.95	7.25%	6.89%	2.75%	9.64%
6	Pinnacle West Capital	PNW	47.8%	0.90	7.25%	6.53%	2.75%	9.28%
7	Portland General Electric	POR	48.2%	0.90	7.25%	6.53%	2.75%	9.28%
8	WEC Energy	WEC	46.0%	0.80	7.25%	5.80%	2.75%	8.55%
9	Xcel Energy	XEL	41.0%	0.80	7.25%	5.80%	2.75%	8.55%
9	**Average**		**45.2%**	**0.83**	**7.25%**	**6.04%**	**2.75%**	***8.79%***
10	High							9.64%
11	Low							8.19%

Sources

Column (b) Per SEC Filings: Average for the four quarters ended December 2020.

Column (c) The Value Line Investment Survey of March 12, April 23 and May 14, 2021 for proxy companies.

Column (d) Reflects the average returns of Large Stocks (12.16%) vs Long Term Gov't Bond Income Returns (4.91%) for the period 1926 to 2020 per the Ibbotson Clasic Year Book (See AG Workpapers)

Column (f) Based on Blue Chip consensus estimate as set forth in May 4, 2021 report showing 2.7% and 2.8% for 2nd & 3rd quarters of 2022 (see AG-DG-616)

Equation for CAPM $K_e = R_f + (B \times R_p)$

Where K_e = the Cost of Common Equity; R_f = the Risk Free Rate of Return;
B = the Beta or covariance of the stocks price to overall market ; and
R_p = the Expected Risk Premium of the overall market

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company - Electric Rate Case

Exhibit AG-1.37
Case No. U-20963
June 22, 2021

Utility Equity Risk Premium Approach

Line	Description (a)	Rate Developed (b)	Note (c)
1	Number of Companies in proxy group	9	
2	Average Rating	BBB/Baa	1
3	Projected Baa Bond Yield	4.30%	2
4	Historical Spread - Electric Util. Common Stocks vs. Utility Bonds	4.52%	3
5	**Cost of Common Equity (Line 5 + Line 6)**	**8.82%**	

1 Except for Portland General Electric (A rated), all companies in the peer group are rated BBB or Baa by one or both of Moody's and S & P
2 Blue Chip Baa Projection for 2021 per AG-CE-616
3 This rate reflects Company Exhibit A-14 (TAW-1), Sched. D-5, page 9 and is the 1932-2020 average (bottom of page)

MICHIGAN PUBLIC SERVICE COMMISSION | **Exhibit AG-1.38**
Consumers Energy Company - Electric Rate Case | **Case No. U-20963**
June 22, 2021
Market to Book Equity Ratios | **Page 1 of 1**

Line	Company & Ticker		Mar. 31, 2021 Mkt. Price p/ Sh.	Mar. 31, 2021 Book Value of Common Equity ($Mil.)	Mar. 31, 2021 Shares Outstanding (Millions)	Book Value Per Sh.	Market to Book Ratio
	(a)		(b)	(c)	(d)	(e)	(f)
	Proxy Group						
1	Alliant Energy	LNT	$ 54.16	$ 5,766.0	250.1	23.05	2.3
2	Ameren	AEE	81.36	9,148.0	255.5	35.80	2.3
3	American Electric Power	AEP	84.70	20,973.0	519.5	40.37	2.1
4	Consolidated Edison	ED	74.80	19,033.0	342.0	55.65	1.3
5	Evergy	EVRG	59.53	8,806.0	227.0	38.79	1.5
6	Pinnacle West Capital	PNW	81.35	5,682.0	112.8	50.37	1.6
7	Portland General Electric	POR	47.47	2,675.0	89.6	29.85	1.6
8	WEC Energy	WEC	93.59	10,767.0	315.4	34.14	2.7
9	Xcel Energy	XEL	66.51	14,700.0	538.1	27.32	2.4
13	**Average**						**2.0**

Col. (b) Price per Share per Yahoo
Col. (c) Per SEC Filings
Col. (d) Per SEC Filings
Col. (e) Equals Col. (c) divided by Col. (d)
Col. (f) Equals Col. (b) divided by Col. (e)

MICHIGAN PUBLIC SERVICE COMMISSION | **Exhibit AG-1.39**
Consumers Energy Company - Electric Rate Case | **Case No. U-20963**
June 22, 2021

Electric Rate Case Return on Equity (ROE) Rates (2019 and 2020)*

ROEs Under 10%

	Electric Company	Jurisdiction & Order Date**			ROE Awarded in 2019	ROE Awarded in 2020	Parent Company	Pub. Finan'ls Avail.	Long Term Debt Issued Since Date of Rate Order*
1	Appalachian Power	WV	Feb. 27	2019	9.75%		American Elec. Power	Yes	Mar. 4, 2019: 400M, 30 Yr. at4.5%
2	Atlanta City Electric	NJ	Mar. 13	2019	9.60%		Exelon	Yes	Mar. 30, 2020: $1.25B, 10 Yr. at 4.05%
3	Orange & Rockland Utlities	NY	Mar. 14	2019	9.00%		Con. Edison	Yes	
4	P. S. Co. of Oklahoma	OK	Mar. 14	2019	9.40%		American Elec. Power	Yes	Mar. 1, 2020: $$400M, 30 Yr. at 3.25%
5	Patomac Edison	MD	Mar. 22	2019	9.65%		First Energy	Yes	June 3, 2020: $300M, 6 Yr. at 1.6%
6	Kentucky Utilities	KY	Apr. 30	2019	9.73%		PPL Corp.	Yes	Sep. 3, 2019: $400M, 30 Yr. at 3.0%
7	Louisville Gas & Electric	KY	Apr. 30	2019	9.73%		PPL Corp.	Yes	Sep. 3, 2019: $400M, 30 Yr. at 3.0%
8	Duke Energy Carolinas	SC	May 1	2019	9.50%		Duke	Yes	Aug. 12, 2019: $350M, 30 Yr. at 3.2%
9	Duke Energy Progress	SC	May 8	2019	9.50%		Duke	Yes	June 4, 2019: $600M, 30 Yr. at 4.2%
10	Otter Tail Power	SD	May 14	2019	8.75%		Otter Tail Power	Yes	Sep. 12, 2019: $175M, 10 &30 Yr
11	Maui Electric	HI	May 16	2019	9.50%		Hawaiian Elec. Industries	Yes	
12	Upper Peninsula Power	MI	May 23	2019	9.90%			Private	
13	Patomac Electric Power	MD	Aug. 12	2019	9.60%		Exelon	Yes	Mar. 30, 2020: $1.25B, 10 Yr. at 4.05%
14	Green Mountain Power	VT	Aug. 29	2019	9.06%		Enegir	Private	
15	Massachusetts Electric	MA	Sep. 30	2019	9.60%		National Grid,PLC	FRN	
16	Entergy New Orleans	LA	Nov. 7	2019	9.35%		Entergy	Yes	May 30, 2020: $600M, 30 Yr. at 3.75
17	Avista Corp	ID	Nov. 29	2019	9.50%		Avista	Yes	
18	Commonwealth Edison	IL	Dec. 4	2019	8.91%		Exelon	Yes	Mar. 30, 2020: $1.25B, 10 Yr. at 4.05%
19	Northern Indiana P. S. Co.	IN	Dec. 4	2019	9.75%		NIPSCO	Yes	Apr. 7, 2020: $1.0B, 10 Yr. at 3.6%
20	Ameren Illinois	IL	Dec. 16	2019	8.91%		Ameren	Yes	Feb. 24, 2021: $450M, 7 Yr. at 1.75%
21	Baltimore Gas & Electric	MD	Dec. 17	2019	9.70%		Exelon	Yes	Mar. 30, 2020: $1.25B, 10 Yr. at 4.05%
22	NorthWestern Corp.	MT	Oct. 29	2019	9.65%		NorthWestern Corp	Yes	Mar. 19, 2021: $100M, 3 Yr. at 1.03%
23	Southwestern Electric Pwr	AR	Dec. 20	2019	9.45%		American Electric Power	Yes	Mar. 1, 2020: $$400M, 30 Yr. at 3.25%
24	Sierra Pacific Power	NV	Dec. 24	2019	9.50%		Berkshire Hathaway	Private	
25	Consolidated Edison-NY	NY	Jan. 6	2020		8.80%	Consolidated Edison	Yes	Mar. 26, 2020: $1.7, 10-30 Yr. @ 3.35% & 3.95%
26	Rockland Electric	NJ	Jan. 22	2020		9.50%	Consolidated Edison	Yes	Mar. 26, 2020: $1.7, 10-30 Yr. @ 3.35% & 3.95%
27	Indiana Michigan Power	MI	Jan. 23	2020		9.86%	American Electric Power	Yes	Nov. 16, 2020: $1.5B, 3-5 Yr. @ 0.75% & 1.0%
28	Public Service-Colorado	CO	Feb. 11	2020		9.30%	Xcel Energy	Yes	Sep. 22, 2020: $500M, 3 Yr. at 0.50%%
29	Houston Electric	TX	Feb. 14	2020		9.40%	CenterPoint	Yes	
30	Central Maine Power	ME	Feb. 19	2020		8.25%	Avangrid	Yes	

* A summary of all returns below 10% as well as at 10% and above is included on page 3 of this exhibit
** All ROE data for this page has been obtained from Regulatory Research Associates

MICHIGAN PUBLIC SERVICE COMMISSION **Exhibit AG-1.39**
Consumers Energy Company - Electric Rate Case **Case No. U-20963**
June 22, 2021
Electric Rate Case Return on Equity (ROE) Rates (2019 and 2020) **Page 2 of 3**

ROEs Under 10%

Line	Electric Company	Jurisdiction & Order Date			ROE Awarded in 2019	ROE Awarded in 2020	Parent Company	Pub. Finan'ls Avail.	Long Term Debt Issued Since Date of Rate Order*
1	Virginia Electric & Power	NC	Feb. 24	2020		9.75%	Dominion Resources	Yes	Dec. 1, 2020 : $900M, 30 Yr. at 2.45%
2	AEP Texas	TX	Feb. 27	2020		9.40%	American Electric Power	Yes	Jun. 29, 2020: $600M, 10 Yr. at 2.10%
3	Indiana Michigan Power	IN	Mar. 11	2020		9.70%	American Electric Power	Yes	Nov. 16, 2020: $1.5B, 3-5 Yr. @ 0.75% & 1.0%
4	Avista	WA	Mar. 25	2020		9.40%	Avista	Yes	
5	Fitchburg Gas & Electric	MA	Apr. 17	2020		9.70%	Unitil	Yes	
6	Duke Energy Kentucky	KY	Apr. 27	2020		9.25%	Duke Energy	Yes	May. 13, 2020: $500M, 10 Yr. at 2.45%
7	DTE Electric	MI	May. 8	2020		9.90%	DTE Energy	Yes	Sep. 29, 2020: $750M, 2 Yr. at 0.55%
8	Southwestern Pub. Serv.	NM	May. 20	2020		9.45%	Xcel Energy	Yes	Sep. 22, 2020: $500M, 3 Yr. at 0.50%
9	Duke Energy Indiana	IN	Jun. 29	2020		9.70%	Duke Energy	Yes	
10	Liberty Utilities	NH	Jun. 30	2020		9.10%	Algonquin Pwr & Utilities	Yes	Sep. 22, 2020: $600M, 10 Yr. at 2.05%
11	Pudget Sound Energy	WA	Jul. 8	2020		9.40%		Private	
12	Delmarva Pwr. & Light	MD	Jul. 14	2020		9.60%	Exelon	Yes	
13	Hawaii Electric & Light	HI	Jul. 28	2020		9.50%	Hawaiian Electric Indust.	Yes	
14	Green Mountain Power	VT	Aug. 27	2020		8.20%	Enegir	Private	
15	Southwestern Pub. Serv.	TX	Aug. 27	2020		9.45%	Xcel Energy	Yes	Sep. 22, 2020: $500M, 3 Yr. at 0.50%%
16	Hawaiian Electric	HI	Oct. 22	2020		9.50%	Hawaiian Electric Indust.	Yes	
17	Jersey Central Pwr. & Lgt.	NJ	Oct. 28	2020		9.60%	First Energy	Yes	
18	NY State Electric & Gas	NY	Nov. 19	2020		8.80%	Avangrid	Yes	
19	Rochester Gas & Electric	NY	Nov. 19	2020		8.80%	Avangrid	Yes	
20	Appalachian Power	VA	Nov. 24	2020		9.20%	American Electric Power	Yes	
21	Madison Gas & Electric	WI	Nov. 24	2020		9.80%	Madison Gas & Electric	Yes	
22	Ameren Ilinois	IL	Dec. 9	2020		8.38%	Ameren	Yes	Feb. 24, 2021: $450M, 7 Yr. at 1.75%
23	Commenwealth Edison	IL	Dec. 9	2020		8.38%	Exelon	Yes	
24	Nevada Power	NV	Dec. 10	2020		9.40%	Berkshire Hathaway	Private	
25	Pacificorp	WA	Dec. 14	2020		9.50%	Berkshire Hathaway	Private	
26	Public Service Co - NH	NH	Dec. 15	2020		9.30%	Eversource	Yes	Mar. 8, 2021: $350M, 10 Yr. at 2.55%
27	Baltimore Gas & Electric	MD	Dec. 16	2020		9.50%	Exelon	Yes	
28	Consumers Energy	MI	Dec. 17	2020		9.90%	CMS Energy	Yes	
29	Pacificorp	OR	Dec. 18	2020		9.50%	Berkshire Hathaway	Private	
30	Tucson Electric Power	AZ	Dec. 22	2020		9.15%	Fortis	FRN	
31	Pacificorp	UT	Dec. 30	2020	-	9.65%	Berkshire Hathaway	Private	
	Average ROE Awarded (Pg. 1 & 2)				9.46%	9.32%			

Electric Rate Case Return on Equity (ROE) Rates (2019 and 2020)

Summary of All Cases (incl. 10% and Over)

Line	Caption/No. of Cases		ROE	2019	2020	Note
1	**Number of ROE Decisions Under 10%**			24	37	Pgs 1 & 2
	ROEs Awarded at 10% or Higher					
	Michigan	Consumers Energy	**10.00%**	1		A
	Michigan	DTE Electric	**10.00%**	1		A
	Iowa	Interstate Power & Light	**10.02%**		1	A
	Wisconsin	Northern States Power	**10.00%**	1		A
	Wisconsin	Wisconsin Electric	**10.00%**	1		A
	Wisconsin	Wisconsin Public Service	**10.00%**	1		A
	Wisconsin	Wisconsin Power & Light	**10.00%**		1	A
	Georgia	Georgia Power	**10.50%**	1		B
	California	Pacific Gas & Electric	**10.25%**	1		C
	California	San Diego Gas & Electric	**10.20%**	1		C
	California	Southern California Edison	**10.30%**	1		C
	California	PacifiCorp	**10.00%**		1	C
	California	Liberty Utilities	**10.00%**		1	C
8	Total Cases with ROEs Stated (Excl. Lmtd. Issue Riders)			**33**	**41**	
	Avg. ROE Rate Awarded	**Excluding 10% Plus Cases**		**9.46%**	**9.32%**	
		All Cases		**9.64%**	**9.39%**	

A In general, Michigan, Iowa and Wisconsin are outliers in the move to reduce authorized ROEs

B Nuclear Risk: Georgia Power is involved in construction of two nuclear plants which are delayed following the bankruptcy of Georgia Power's original contractor. Southern Company (parent) and Georgia Power have written off approximately $1 Billion of cost overruns and significant asset sales have been made to finish the projects. Regulators are supportive with higher authorized ROE rates.

C Wildfire Risk: Some California companies have been financially ravaged by wildfire damages causing substantial write-offs of uninsurred excess damages and which has forced Pacific Gas & Electric into bankruptcy.

D All ROE data for this page has been obtained from Regulatory Research Associates

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy - Electric Rate Case

Exhibit AG-1.40
Case No. U-20963
June 22, 2021

AG Peer Group Selection

			Elimination Factors											
			Revenues						Nuclear					
		2020	Over	Under	Div. Risk or		Reorg.	EPS	O/S Wind	Rtngs.			Peer Group per	
	Value Line Electric Utilities	Revs. ($M)	$17.5 Bil	$1.75 Bil	No Div. Grth	Foreign	M & A	Fall-Off	W. Fire	Unknown	Other	Total	AG	CECo
1	AVANGRID	$ 6,320			Yes		Yes					2		
2	Consolidated Edison	12,246											x	
3	Dominion Resources	14,172			Yes				Yes			2		
4	Duke Energy	23,868	Yes				Yes					2		
5	Eversource Energy	8,904							Yes			1		
6	Exelon	33,039	Yes				Yes	Yes				3		
7	FirstEnergy	10,790			Yes						Legal Woes*	2		
8	NextEra Energy	17,997	Yes				Yes					2		
9	PPL Corp.	7,607			Yes	Yes	Yes					3		
10	Public Service Enterp. Group	9,603					Yes	Yes				2		
11	Southern Co.	20,375	Yes						Yes			2		
12	ALLETE	1,169		Yes				Yes				2		
13	Alliant Energy	3,416											x	x
14	Ameren	5,794											x	x
15	American Electric Power	14,918											x	
16	CMS Energy	6,680									CMS	1		
17	CenterPoint Energy	7,418					Yes					1		
18	DTE Energy	12,177					Yes					1		x
19	Entergy	10,114						Yes				1		
20	Evergy	4,913											x	x
21	Fortis	8,935				Yes						1		
22	MGE Energy	539		Yes								1		
23	OGE Energy	2,122					Yes					1		
24	Otter Tail	890		Yes								1		
25	WEC Energy	7,242											x	x
26	Avista	1,322		Yes								1		
27	Black Hills	1,697		Yes								1		
28	Edison International	13,578							Yes			1		x
29	Hawaiian Electric	2,580								Yes		1		
30	IDACORP	1,351		Yes								1		
31	Northwestern	1,199		Yes								1		
32	PNM Resources	1,523		Yes			Yes					2		
33	Pinnacle West Capital	3,587											x	x
34	Portland General Electric	2,145											x	x
35	Sempra Energy	11,370				Yes	Yes					2		
36	Xcel Energy	11,256											x	x
	Totals Excl. NISOURCE (in CECo Peer Group)											41	9	9

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U20963-AG-CE-615
Page **1** of **1**

Question:

2. Provide a copy of all rating agency reports covering CMS Energy and Consumers Energy for 2019, 2020, and 2021.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that CMS Energy is not a party to this case. Subject to the Company's objection, and without waiving that objection, Consumers Energy responds as follows:

Please find the requested ratings agency credit opinions for Consumers Energy in U20963-AG-CE-615-Bleckman_ATT_1.

MARC R. BLECKMAN
May 14, 2021

Financial Planning & Analysis

SEE ATTACHMENT OF 93 PAGES WITH RATING AGENCY REPORTS

Exhibit: AG-1.41

S&P Global
Ratings

RatingsDirect®

Consumers Energy Co.

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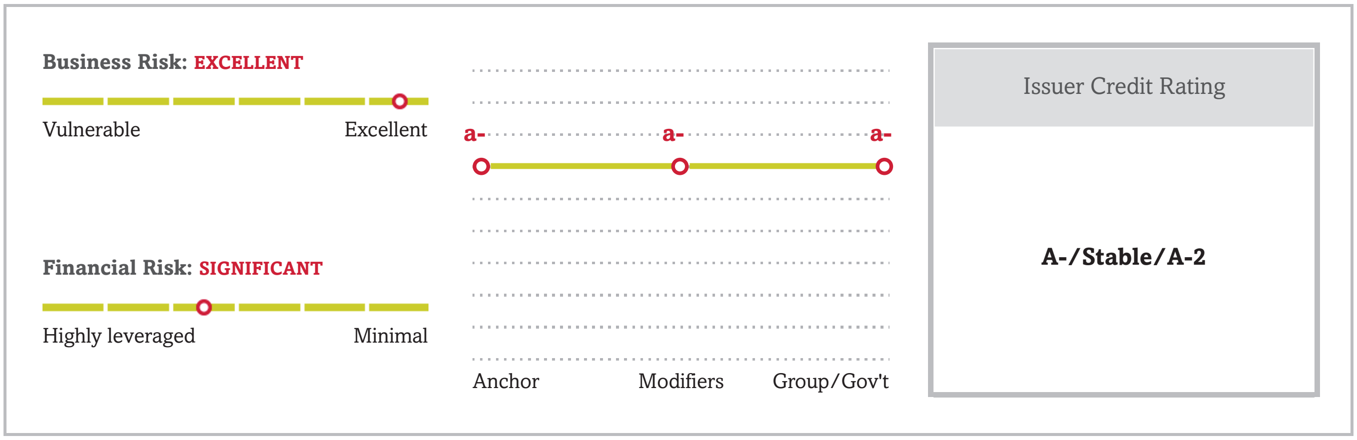
Consumers Energy Co.



Credit Highlights

Overview

Key strengths	Key risks
Larger-than-average vertically integrated electric utility and gas distribution utility.	Limited geographic and regulatory diversity makes the company largely dependent on Michigan regulators to sustain credit quality.
Favorable regulatory construct in Michigan.	Significant exposure to carbon emission risk through high reliance on natural gas and coal-fired generation.
Effectively managed the associated risks of the COIVD-19 pandemic.	Negative discretionary cash flow, reflecting robust capital spending, necessitating constant access to fairly priced capital markets.
Sufficient insulating measures for higher rating than group credit profile.	

The above-average regulatory environment in Michigan should continue to allow for consistent and constructive regulatory outcomes. Consumers Energy Co.'s most recent electric rate case order led to an increase in revenue of about $90 million. This revenue increase incorporates the return of remaining deferred taxes from the Tax Cuts and Jobs Act (TCJA) to electric customers and reflects a lower return on equity (ROE; 9.9% compared to 10%) and a lower equity ratio (51.11% compared to 52.50%). Although we view resolving the effects of tax reform through this rate case as favorable, if lower ROEs and a lower equity ratio persist, credit quality could weaken.

The most recent gas rate case order led to an increase in revenue by $144 million and maintained a consistent ROE of 9.9% and equity ratio of 52.05%. However, this outcome was slightly offset by a stay-out agreement that restricts Consumers Energy from filing another gas rate case before December 2021. We believe this outcome, while supportive of credit quality, may eventually lead to some regulatory lag because of the stay-out provision.

Because we assess the lower ROE and equity ratio in the electric rate case and the stay-out provision on the gas side as one-time decisions, we expect that the utility will continue to effectively manage regulatory risk through the use of various constructive rate mechanisms made available by the Michigan Public Service Commission (MPSC). In general, we view Michigan's regulatory construct as above average compared to peers because of the benefit of forward-looking test years, a stream-lined 10-month rate case process, and various constructive rate mechanisms--such as power supply and natural gas cost rider adjustments and partial decoupling for the gas business--which help the company earn its allowed ROE and minimize regulatory lag.

The company effectively managed COVID-19-related risks. Given Consumers Energy's mostly residential customer base (about 60%), the company's exposure to the large commercial and industrial sales declines across the industry has been more limited than for many of its peers. Additionally, the company achieved cost savings of about $100 million during the year by reducing operating and maintenance expenses, and it continues to pursue other cost efficiency strategies, offsetting incremental COVID-19-related expenses. Additionally, Consumers Energy received a constructive order from the MPSC in April 2020, which reduced the effect of bad debt expense on earnings by allowing the company to defer incremental uncollectible accounts related to the pandemic.

The company's elevated utility capital spending plan prioritizes infrastructure upgrades and renewable energy. Over the next five years, Consumers Energy plans to spend about $9.4 billion to maintain and upgrade its gas infrastructure and electric distribution systems. The capital plan includes elevated investment of about $5 billion in the gas segment, as well as about $2.8 billion in electric supply projects, which primarily focus on renewable generation.

Consumers Energy has significant carbon emissions through its heavy reliance on natural gas and coal generation. While most of Consumers Energy's electricity is generated from natural gas (about 37%) and coal (about 29%), the company intends to reduce its carbon exposure through its Clean Energy Plan. The plan includes a 2040 long-term goal to significantly reduce carbon emissions of its owned generation by more than 90% from 2005 and eliminate coal-sourced electric generation. The plan also provides the foundation for the utility to achieve net-zero carbon emissions by 2040.

We expect Consumers Energy's consolidated credit measures to remain in the middle of the range for its financial risk profile category. Although we expect some modest weakening in financial metrics as a result of the recent electric rate case order, as well as some potential regulatory lag, we believe the company will continue to manage its funds from operations (FFO) to debt at about 20% over the next three years, consistent with the middle of the range for its financial risk profile category.

Outlook: Stable

The stable rating outlook on Consumers Energy reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect Consumers Energy will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt at about 20%.

Downside scenario

We could lower our rating on Consumers Energy if its stand-alone financial measures weaken such that 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 Corp.

Upside scenario

Although less likely, we could raise our rating on Consumers Energy if we raise our rating on CMS Energy and Consumers Energy's stand-alone financial measures improve, reflecting FFO to debt of consistently above 20%.

Our Base-Case Scenario

Assumptions

- Consistent rate case filings and use of existing regulatory mechanisms;
- Elevated capital spending over the forecast period averaging $2.4 billion annually;
- Annual dividends of $600 million-$900 million annually;
- Equity distributions to parent CMS Energy, averaging $530 million annually;
- All debt maturities are refinanced; and
- Continued negative discretionary cash flow will be financed in a balanced manner to support the regulated capital structure.

Key metrics

Table 1

Consumers Energy Co.--Key Metrics*

	2019a	2020e	2021e
FFO to debt (%)	22.1	20-22	19-21
Debt to EBITDA (x)	3.7	3.5-4.5	4-5
FFO interest coverage	7.2	6.5-7.5	6-7

*All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. FFO--Funds from operations.

Company Description

Consumers Energy is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 3.6 million customers in Michigan. Consumers Energy's electric business operates as a vertically integrated utility that generates, distributes, and sells electricity. The electric utility sources about half of its generation from purchased power, rather than from its own plants. The company also sells, stores, and transports natural gas. It is based in Jackson, Mich.

Peer Comparison

Table 2

Consumers Energy Co.--Peer Comparison

Industry sector: Combo

	Consumers Energy Co.	DTE Electric Co.	Alliant Energy Corp.	Ameren Corp.	WEC Energy Group Inc.
Rating as of Jan. 19, 2021	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2019--				

Table 2

Consumers Energy Co.--Peer Comparison (cont.)

Industry sector: Combo

	Consumers Energy Co.	DTE Electric Co.	Alliant Energy Corp.	Ameren Corp.	WEC Energy Group Inc.
(Mil. $)					
Revenue	6,341.5	5,224.0	3,647.7	5,910.0	7,523.1
EBITDA	2,251.6	2,297.4	1,384.2	2,396.0	2,727.6
FFO	1,823.4	1,942.7	1,099.5	1,991.7	2,250.1
Interest expense	335.2	464.8	300.2	433.3	541.3
Cash interest paid	296.2	308.8	305.3	391.3	502.4
Cash flow from operations	1,688.4	1,739.7	629.5	2,132.7	2,401.9
Capital expenditure	2,190.9	2,192.3	1,612.9	2,422.0	2,302.9
FOCF	(502.5)	(452.6)	(983.4)	(289.3)	99.0
DCF	(1,094.5)	(946.6)	(1,316.0)	(793.3)	(796.2)
Cash and short-term investments	11.0	12.0	16.3	16.0	37.5
Debt	8,237.6	9,086.9	7,206.1	9,728.8	13,145.8
Equity	7,737.0	7,195.0	5,305.1	8,130.0	10,489.4
Adjusted ratios					
EBITDA margin (%)	35.5	44.0	37.9	40.5	36.3
Return on capital (%)	7.7	8.2	7.7	7.7	7.6
EBITDA interest coverage (x)	6.7	4.9	4.6	5.5	5.0
FFO cash interest coverage (x)	7.2	7.3	4.6	6.1	5.5
Debt/EBITDA (x)	3.7	4.0	5.2	4.1	4.8
FFO/debt (%)	22.1	21.4	15.3	20.5	17.1
Cash flow from operations/debt (%)	20.5	19.1	8.7	21.9	18.3
FOCF/debt (%)	(6.1)	(5.0)	(13.6)	(3.0)	0.8
DCF/debt (%)	(13.3)	(10.4)	(18.3)	(8.2)	(6.1)

FFO--Funds from operations. FOCF--Free operating cash flow. DCF--Discretionary cash flow.

Business Risk: Excellent

Our assessment of Consumers Energy's business risk profile reflects the company's lower-risk electric and natural gas utility operations. Consumers Energy is a larger-than-average utility that serves about 1.8 million electric customers and about 1.8 million natural gas customers throughout Michigan. In addition, about 80% of the company's electric customer revenue base is residential and commercial, providing stable cash flow and mitigating the company's exposure to industrial cyclicality. Consumers Energy is a wholly owned subsidiary of CMS Energy and contributes about 95% of CMS Energy's consolidated operations.

The MPSC regulates Consumers Energy. We view the regulatory environment in Michigan as above average compared to peers as demonstrated through the company's benefit from forward-looking test years and a stream-lined 10-month rate case process. Consumers Energy also receives other constructive rate mechanisms, such as the Power Supply Cost Recovery and Gas Cost Recovery adjustment riders, as well as partial decoupling for the gas business, which annually reconciles actual weather-normalized non-fuel revenues with the revenues approved by the MPSC. These constructive rate mechanisms enable Consumers Energy to generally earn its allowed ROE and minimize regulatory lag.

The company's most recent electric rate case became effective in January 2021, and it increased revenue by about $90 million. The order incorporated an equity ratio of 51.11%, an ROE of 9.9%, and the return of deferred tax liabilities from the TCJA to electric customers through rates. The order also approved the recovery of the balance of the financial compensation mechanism (FCM) approved in Consumers Energy's most recent integrated resource plan. We view the FCM as a constructive rate mechanism because it gives Consumers Energy another way to recover interim expenses by allowing the company to earn a financial incentive on certain power purchase agreements approved after Jan. 1, 2019, through a surcharge. Additionally, the company received approval of a new distributed generation tariff to replace the previous net metering tariff. We view this tariff as a useful mechanism to help Consumers Energy meet its demand response goals pursuant to Michigan's 2016 Energy Law. Although we do not view the lower equity ratio and ROE as supportive of credit quality, we believe this outcome is partially mitigated by the resolution of the effects of tax reform and the incorporation of new constructive rate mechanisms within the rate case. The most recent gas rate case order went into effect in October 2020, and it increased revenue by about $144 million. The order included an equity ratio of 52.05%, an ROE of 9.9%, a stay-out agreement restricting the company from filing another gas rate case before 2021, and it accelerated amortization of certain tax liabilities beginning in October 2021. We view the outcome of this gas rate case as overall supportive of credit quality, despite some potential regulatory lag.

Financial Risk: Significant

We assess Consumers Energy's financial measures using our medial volatility table, reflecting the company's lower-risk regulated electric and gas utility operations and its effective management of regulatory risk. Under our base-case scenario, we expect elevated capital spending averaging $2.4 billion annually over the forecast period, 2021 collective revenue increases of about $234 million from the recent gas and electric rate cases, and a gas rate case stay-out until December 2021. We anticipate financial measures that are consistent with the middle of the company's financial risk category. Specifically, we forecast FFO to debt averaging about 20% over the outlook period.

Financial summary

Table 3

Consumers Energy Co.--Financial Summary

Industry sector: Combo					
	--Fiscal year ended Dec. 31--				
	2019	**2018**	**2017**	**2016**	**2015**
(Mil. $)					
Revenue	6,341.5	6,430.1	6,186.8	6,029.5	6,081.8
EBITDA	2,251.6	2,151.9	2,267.1	2,168.3	2,010.8

Table 3

Consumers Energy Co.--Financial Summary (cont.)

Industry sector: Combo

	--Fiscal year ended Dec. 31--				
	2019	**2018**	**2017**	**2016**	**2015**
FFO	1,823.4	1,665.1	1,953.7	1,820.4	1,779.5
Interest expense	335.2	354.9	347.4	332.8	340.3
Cash interest paid	296.2	330.9	314.4	297.8	315.3
Cash flow from operations	1,688.4	1,533.1	1,791.7	1,768.4	1,814.5
Capital expenditure	2,190.9	1,920.3	1,721.1	1,753.7	1,615.1
FOCF	(502.5)	(387.2)	70.6	14.7	199.4
DCF	(1,094.5)	(918.2)	(453.4)	(486.3)	(276.6)
Cash and short-term investments	11.0	39.0	44.0	131.0	50.0
Gross available cash	11.0	39.0	44.0	131.0	50.0
Debt	8,237.6	7,774.2	7,037.4	6,734.0	7,106.7
Equity	7,737.0	6,920.0	6,488.0	5,939.0	5,546.0
Adjusted ratios					
EBITDA margin (%)	35.5	33.5	36.6	36.0	33.1
Return on capital (%)	7.7	7.9	9.8	9.7	10.1
EBITDA interest coverage (x)	6.7	6.1	6.5	6.5	5.9
FFO cash interest coverage (x)	7.2	6.0	7.2	7.1	6.6
Debt/EBITDA (x)	3.7	3.6	3.1	3.1	3.5
FFO/debt (%)	22.1	21.4	27.8	27.0	25.0
Cash flow from operations/debt (%)	20.5	19.7	25.5	26.3	25.5
FOCF/debt (%)	(6.1)	(5.0)	1.0	0.2	2.8
DCF/debt (%)	(13.3)	(11.8)	(6.4)	(7.2)	(3.9)

FFO--Funds from operations. FOCF--Free operating cash flow. DCF--Discretionary cash flow.

Reconciliation

Table 4

Consumers Energy Co.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

	--Fiscal year ended Dec. 31, 2019--								
Consumers Energy Co. reported amounts (mil. $)									
	Debt	**Shareholders' equity**	**Revenue**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	7,369.0	7,700.0	6,376.0	2,105.0	1,130.0	297.0	2,251.6	1,601.0	2,085.0
S&P Global Ratings' adjustments									
Cash taxes paid	--	--	--	--	--	--	(132.0)	--	--
Cash interest paid	--	--	--	--	--	--	(279.0)	--	--
Reported lease liabilities	106.0	--	--	--	--	--	--	--	--
Operating leases	--	--	--	9.0	1.5	1.5	(1.5)	7.5	--

Table 4

Consumers Energy Co.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts (cont.)									
Postretirement benefit obligations/deferred compensation	194.3	--	--	--	--	--	--	--	--
Accessible cash and liquid investments	(11.0)	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	4.0	(4.0)	(4.0)	(4.0)
Share-based compensation expense	--	--	--	21.0	--	--	--	--	--
Securitized stranded costs	(251.0)	--	(34.5)	(34.5)	(8.5)	(8.5)	8.5	(26.0)	--
Power purchase agreements	545.8	--	--	130.1	20.2	20.2	(20.2)	109.9	109.9
Asset-retirement obligations	374.5	--	--	21.0	21.0	21.0	--	--	--
Nonoperating income (expense)	--	--	--	--	10.0	--	--	--	--
Noncontrolling interest/minority interest	--	37.0	--	--	--	--	--	--	--
Debt: Other	(90.0)	--	--	--	--	--	--	--	--
Total adjustments	868.6	37.0	(34.5)	146.6	44.2	38.2	(428.2)	87.4	105.9
S&P Global Ratings' adjusted amounts									
	Debt	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	8,237.6	7,737.0	6,341.5	2,251.6	1,174.2	335.2	1,823.4	1,688.4	2,190.9

Liquidity: Adequate

As of Sept. 30, 2020, we assess Consumers Energy's liquidity as adequate to cover its needs over the next 12 months, even if consolidated EBITDA declines 10%. We expect the company's liquidity sources will exceed uses by more than 1.1x during this period. Our assessment also reflects Consumers Energy's sound relationships with banks, satisfactory standing in the credit markets, and generally prudent risk management.

Principal liquidity sources	Principal liquidity uses
• Cash of about $199 million; • Credit facility availability of about $1.09 billion; and • Estimated cash FFO of about $1.99 billion.	• Long-term debt maturities of about $557 million; • Working capital outflows of about $274 million; • Maintenance capital spending of about $1.29 billion; and • Dividends of about $690 million.

Environmental, Social, And Governance

We assess Consumers Energy's environmental risks as somewhat higher than peers' to reflect the relatively higher percentage of electricity generated from fossil fuels. We assess the company's social and governance risk factors as in line with those of its peers.

About 37% of Consumers Energy's owned and purchased generation use is from natural gas, 29% is from coal, 19% is from nuclear, and 10% is from renewables. The company's significant reliance on fossil fuels exposes it to the potential for changing environmental regulations that may result in higher operating costs, require significant capital investment, lead to premature plant closures, or increase operating risks. However, the company has been offsetting some of these risks through strategic reduction of its environmental liabilities through coal plant retirements and by increasing the proportion of natural gas and renewables in its generation portfolio. The utility's capital plan and its ongoing investment in MPSC-approved wind and solar projects demonstrate a commitment to invest in renewable generation. These planned utility investments are in line with the company's Clean Energy Plan, which includes a 2040 long-term goal to reduce carbon emissions of owned generation by more than 90% from 2005, eliminate the use of coal-sourced electric generation, and target net-zero carbon emissions.

On the gas side, the company's older assets are susceptible to natural gas leaks, which emit methane. Although aging infrastructure poses a clear operational risk, the company plans significant investment in gas infrastructure upgrades over the next few years and has announced a net-zero methane goal from its natural gas delivery system by 2030.

Group Influence

Under our group rating methodology, we consider CMS Energy as the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess Consumers Energy as a core subsidiary of CMS Energy because we view the utility as integral to the group's identity, highly unlikely to be sold (95% of the consolidated company), and having a strong commitment from management, given the company's emphasis on maintaining the size of the regulated utility operations relative to the nonutility businesses.

Because Consumers Energy is operationally separate and sufficient insulating measures are in place, we rate the utility one notch above the GCP. Some of the key insulating measures in place include the following:

- Consumers Energy is a separate and stand-alone legal entity that functions independently (both financially and operationally), files its own rate cases, and is independently regulated by MPSC.
- Consumers Energy has its own records and books, including stand-alone audited financial statements.
- The utility has its own funding arrangements, including issuing its own long-term debt, and it has a separate committed credit facility to cover its short-term funding needs.
- Consumers Energy does not comingle funds, assets, or cash flow with parent CMS Energy or its other subsidiaries,

and it does not participate in a money pool.

- We believe there is a strong economic basis for CMS Energy to preserve Consumers Energy's credit strength, reflecting Consumers Energy's low-risk, profitable, and regulated utility business model. Consumers Energy is also a significant portion of CMS Energy, accounting for about 95% of the consolidated company.
- There are no cross-default provisions between parent CMS Energy and Consumers Energy that could directly lead to a default at the utility.

Issue Ratings – Subordination Risk Analysis

Capital structure

As of Sept. 30, 2020, Consumers Energy's capital structure consisted of about $8.4 billion of long-term debt, including about $8 billion in first mortgage bonds (FMBs).

Analytical conclusions

We base our 'A-2' short-term rating on Consumers Energy on our issuer credit rating.

Issue Ratings - Recovery Analysis

- We assign recovery ratings to FMBs issued by U.S. utilities, which can result in issue ratings being notched above an issuer credit rating on a utility, depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of secured utility bonds (SUBs) that qualify for a recovery rating as defined in our criteria.
- The recovery methodology is supported by our expectation of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhance recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization, given the essential service provided and the high replacement cost) will persist.
- Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed an issuer credit rating on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories, depending on the calculated ratio.
- Consumers Energy's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low

- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** bbb+
- **Entity status within group:** Insulated (no impact)

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, July 1, 2019
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of January 27, 2021)*

Consumers Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Issuer Credit Ratings History	
30-Oct-2019	A-/Stable/A-2
03-Dec-2014	BBB+/Stable/A-2
11-Sep-2014	BBB/Positive/A-2
Related Entities	
CMS Energy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Junior Subordinated	BBB-
Senior Unsecured	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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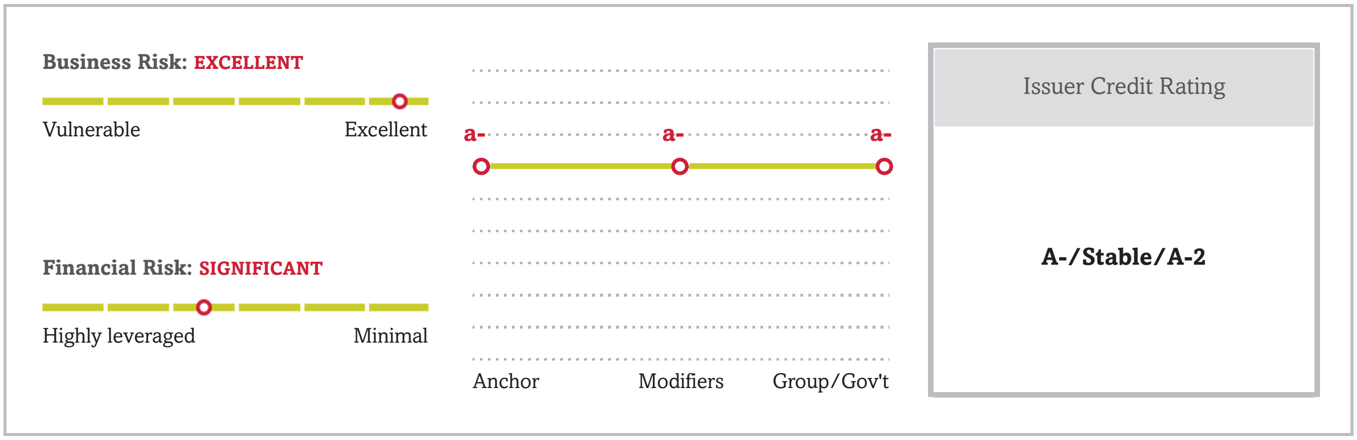
Consumers Energy Co.



Credit Highlights

Overview

Key strengths	Key risks
Lower-risk vertically integrated electric utility operations and gas distribution operations.	Limited geographic and regulatory diversity with operations concentrated in Michigan.
Above-average management of regulatory risk compared to peers.	Elevated exposure to carbon emissions through its high reliance on natural gas and coal-fired generation.
Large electric and natural gas customer base of about 3.6 million combined electric and gas customers.	Weakening financial metrics due to the effects of tax reform.

The above-average regulatory environment in Michigan should continue to allow for consistent and generally constructive regulatory outcomes despite the recent effects of tax reform. The company's most recent electric rate case order decreases rates by $24 million, incorporating the effects of tax reform as well as an agreement that the company not file a new electric rate case until 2020. While the company's recent gas rate case order increases revenue by about $144 million, the increase was partially offset by incorporating tax reform, a lower authorized return on equity (ROE) (9.9% compared to 10%), and a lower equity ratio (52.05% compared to 52.50%). We generally would not view an electric rate case reduction, and a gas rate case with a lower authorized ROE and equity ratio as supportive of credit quality; however, we believe that Consumers Energy will continue to effectively manage regulatory risk through the use of the many constructive rate mechanisms made available to the company through the Michigan Public Service Commission (MPSC). We consider Michigan an above-average regulatory jurisdiction compared to peers due to the benefit of forward-looking test years, a streamlined 10-month rate case process, and various constructive rate mechanisms that allow the company to earn its allowed return on equity and minimize regulatory lag.

Consumers Energy has exposure to carbon emissions through the utility's heavy reliance on natural gas and coal generation. While most of the company's electricity is generated from natural gas (about 30%) and coal (about 25%), the company has a long-term plan to significantly reduce its carbon exposure by 90% by 2040.

Outlook: Stable

The stable rating outlook on Consumers Energy Co. reflects S&P Global Ratings' expectation that management will continue focusing on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect that Consumers Energy will maintain stand-alone financial measures consistent with the middle of the range for the significant financial risk profile, specifically funds from operations (FFO) to debt of about 19%.

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.

Upside scenario

We could raise our rating on Consumers Energy if we raise our rating on CMS Energy and Consumers Energy's stand-alone FFO to debt improves to consistently above 20%.

Our Base-Case Scenario

Assumptions

- Electric and gas rate increases and use of existing regulatory mechanisms.
- Modest load growth.
- Annual capital spending of about $2.3 billion.
- Dividends of about $600 million to $800 million range annually.
- All debt maturities refinanced.
- We expect negative discretionary cash flow will be financed in a balanced manner to support its regulated capital structure.

Key Metrics

	2018a	2019e	2020e
FFO to debt (%)	21.4	19.5-20.5	18.5-19.5
Debt to EBITDA (x)	3.6	3.5-4.5	3.5-4.5
FFO cash interest (x)	6.0	5-6	5-6

a--actual. e--estimate. FFO--Funds from operations.

Company Description

Consumers Energy Co. is a subsidiary of CMS Energy Corp. and operates as an electric and gas utility serving around 3.6 million customers in Michigan. Consumers Energy's electric business operates as a vertically integrated utility that generates, transmits, distributes, and sells electricity. The electric utility sources slightly over half of its generation from purchased power rather than its own plants. Consumers also sells, stores, and transports natural gas. The company is based in Jackson, Mich.

Business Risk: Excellent

Our assessment of Consumers Energy's business risk profile reflects the company's lower-risk electric and natural gas utility operations. The company is a large utility serving about 1.8 million electric customers and about 1.8 million natural gas customers throughout Michigan. In addition, about 80% of the company's electric customer revenue base is residential and commercial, providing a stable cash flow and mitigating the company's exposure to industrial cyclicality. Consumers Energy is a wholly owned subsidiary of CMS Energy and contributes about 95% of CMS Energy's consolidated operations.

The MPSC regulates Consumers Energy. We view the regulatory environment in Michigan as above average compared to peers as demonstrated through the company's benefit from forward-looking test years and various constructive rate mechanisms that enable it to generally earn their allowed returns on equity and minimize regulatory lag. In 2019, the company received an electric rate case order reducing revenue by about $24 million. The order incorporated the impacts of tax reform and an agreement for the company to stay out of an electric rate case until 2020. CMS also recently received a $144 million revenue increase through a gas rate case order, which included the effects of tax reform, a reduced ROE, and a lower equity ratio. The company most recently filed for a $245 million gas rate case and we expect a regulatory order by the fourth quarter of 2020.

Peer comparison

Table 1

Consumers Energy Co.--Peer Comparison

Industry Sector: Combo

	Consumers Energy Co.	DTE Energy Co.	Alliant Energy Corp.	Ameren Corp.	WEC Energy Group Inc.
Ratings as of Jan. 16, 2020	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2018--				
(Mil. $)					
Revenue	6,430.1	14,212.0	3,534.5	6,291.0	7,679.5
EBITDA	2,151.9	3,041.7	1,352.4	2,447.0	2,544.1
Funds from operations (FFO)	1,665.1	2,502.0	1,041.7	2,033.3	2,054.5
Interest expense	354.9	682.6	287.2	433.7	506.1
Cash interest paid	330.9	565.7	305.7	392.7	473.3
Cash flow from operations	1,533.1	2,732.0	542.9	2,158.3	2,501.3
Capital expenditure	1,920.3	2,700.3	1,650.2	2,338.0	2,155.4
Free operating cash flow (FOCF)	(387.2)	31.7	(1,107.3)	(179.7)	345.9
Discretionary cash flow (DCF)	(918.2)	(668.7)	(1,414.4)	(652.7)	(435.4)

Table 1

Consumers Energy Co.--Peer Comparison (cont.)					
Industry Sector: Combo					
	Consumers Energy Co.	**DTE Energy Co.**	**Alliant Energy Corp.**	**Ameren Corp.**	**WEC Energy Group Inc.**
Cash and short-term investments	39.0	71.0	20.9	16.0	84.5
Debt	7,774.2	14,400.6	6,902.0	9,166.6	12,183.2
Equity	6,920.0	11,982.0	4,685.7	7,702.0	10,077.5
Adjusted ratios					
EBITDA margin (%)	33.5	21.4	38.3	38.9	33.1
Return on capital (%)	7.9	7.7	7.6	9.4	7.8
EBITDA interest coverage (x)	6.1	4.5	4.7	5.6	5.0
FFO cash interest coverage (x)	6.0	5.4	4.4	6.2	5.3
Debt/EBITDA (x)	3.6	4.7	5.1	3.7	4.8
FFO/debt (%)	21.4	17.4	15.1	22.2	16.9
Cash flow from operations/debt (%)	19.7	19.0	7.9	23.5	20.5
FOCF/debt (%)	(5.0)	0.2	(16.0)	(2.0)	2.8
DCF/debt (%)	(11.8)	(4.6)	(20.5)	(7.1)	(3.6)

Source: S&P Global Ratings.

Financial Risk: Significant

We assess Consumers Energy's financial measures using our medial volatility table, reflecting the company's lower-risk regulated electric and gas utility operations and its effective management of regulatory risk. Under our base-case scenario, we expect financial measures that are consistent with the middle of the range for the company's financial risk profile category. Specifically, we expect FFO to debt of about 19%.

Financial summary

Table 2

Consumers Energy Co.--Financial Summary					
Industry Sector: Combo					
	--Fiscal year ended Dec. 31--				
	2018	**2017**	**2016**	**2015**	**2014**
(Mil. $)					
Revenue	6,430.1	6,186.8	6,029.5	6,081.8	6,754.1
EBITDA	2,151.9	2,267.1	2,168.3	2,010.8	1,938.1
Funds from operations (FFO)	1,665.1	1,953.7	1,820.4	1,779.5	1,361.7
Interest expense	354.9	347.4	332.8	340.3	345.4
Cash interest paid	330.9	314.4	297.8	315.3	310.4
Cash flow from operations	1,533.1	1,791.7	1,768.4	1,814.5	1,391.7

Table 2

Consumers Energy Co.--Financial Summary (cont.)

Industry Sector: Combo	--Fiscal year ended Dec. 31--				
	2018	2017	2016	2015	2014
Capital expenditure	1,920.3	1,721.1	1,753.7	1,615.1	1,652.1
Free operating cash flow (FOCF)	(387.2)	70.6	14.7	199.4	(260.3)
Discretionary cash flow (DCF)	(918.2)	(453.4)	(486.3)	(276.6)	(719.3)
Cash and short-term investments	39.0	44.0	131.0	50.0	34.0
Gross available cash	39.0	44.0	131.0	50.0	34.0
Debt	7,774.2	7,037.4	6,734.0	7,106.7	6,871.5
Equity	6,920.0	6,488.0	5,939.0	5,546.0	5,277.0
Adjusted ratios					
EBITDA margin (%)	33.5	36.6	36.0	33.1	28.7
Return on capital (%)	7.9	9.8	9.7	10.1	10.1
EBITDA interest coverage (x)	6.1	6.5	6.5	5.9	5.6
FFO cash interest coverage (x)	6.0	7.2	7.1	6.6	5.4
Debt/EBITDA (x)	3.6	3.1	3.1	3.5	3.5
FFO/debt (%)	21.4	27.8	27.0	25.0	19.8
Cash flow from operations/debt (%)	19.7	25.5	26.3	25.5	20.3
FOCF/debt (%)	(5.0)	1.0	0.2	2.8	(3.8)
DCF/debt (%)	(11.8)	(6.4)	(7.2)	(3.9)	(10.5)

Source: S&P Global Ratings.

Liquidity: Adequate

Consumers Energy has adequate liquidity in our view and could more than cover its needs for the next 12 months even if consolidated EBITDA declined by 10%. We expect Consumers Energy's liquidity sources over the next 12 months to exceed its uses by more than 1.1x. Under our stress scenario, we do not expect the company would require access to capital markets during the period to meet its liquidity needs. Our assessment also reflects the company's stable cash flow, generally prudent risk management, sound relationships with banks, and a generally satisfactory standing in the credit markets.

The short-term rating on Consumers Energy is 'A-2' based on our issuer credit rating.

Principal Liquidity Sources	Principal Liquidity Uses
• Cash and liquid investments of roughly $260 million; • FFO of about $1.6 billion; and • Credit facility availability of about $1.1 billion.	• Long-term debt maturities of $202 million in 2020; • Maintenance capital spending of about $1.7 billion; and • Dividends of about $640 million.

Debt maturities

- 2020: $202 million
- 2021: $27 million
- 2022: $653 million
- 2023: $354 million

Environmental, Social, And Governance

Consumers Energy sources about 30% of its owned and purchased generation from gas, 25% from coal, 20% from nuclear, and 10% from renewables. The company's significant reliance on fossil fuels exposes it to the potential for changing environmental regulations that may result in higher operating costs, significant capital investment, premature plant closures, or increasing operating risks. However, the company has been offsetting some of these risks through strategic reduction of its environmental liabilities through coal plant retirements and increasing the proportion of natural gas and renewables in its portfolio. The company's most recent 10-year capital plan demonstrates a commitment to invest in renewable generation, especially solar. These investments are in line with the company's integrated resource plan, which targets sourcing 50% of its generation portfolio from renewables and reducing carbon emissions by 90% by 2040.

On the gas side, the company's older assets are susceptible to natural gas leaks, which emit methane. Although aging infrastructure poses a clear operational risk, the company plans significant investment in gas infrastructure upgrades over the next few years and has announced a net-zero methane goal by 2030.

Overall, we assess Consumers Energy's environmental risk as moderately high but still generally in line with its peer group. This incorporates our view of steps the company is taking to mitigate its environmental risks by reducing its coal-fired generation sources, investing in renewable energy sources, upgrading its gas infrastructure, and modernizing its electrical grid. The company's social and governance risk factors are in line with those of its peers. We view Consumers Energy's ability to generally deliver safe and reliable services to its customers as a positive social factor. Additionally, the company has a mostly independent board of directors with a separate chairman of the board and CEO, which is engaged in risk oversight on behalf of all stakeholders.

Group Influence

Under our Group Rating Methodology, we consider CMS Energy as the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess the status of Consumers Energy as a core subsidiary of CMS because we view Consumers as integral to the group's identity, highly unlikely to be sold (95% of the consolidated company), and having a strong management commitment given the company's emphasis on maintaining the size of the regulated utility operations relative to the nonutility businesses.

Because of Consumers' operational separateness and our assessment of the insulating measures in place as sufficient, we rate Consumers one notch above the GCP. Some of the key insulating measures in place include the following:

- Consumers is a separate and stand-alone legal entity that functions independently, both financially and operationally, files its own rate cases, and is independently regulated by the Michigan Public Service Commission (MPSC).
- Consumers has its own records and books including standalone audited financial statements.
- The utility has its own funding arrangements including issuing its own long-term debt and has a separate committed credit facility to cover its short-term funding needs.
- Consumers does not comingle funds, assets, or cash flows with parent CMS or its other subsidiaries and does not participate in a money pool.
- We believe there is a strong economic basis for CMS to preserve Consumers' credit strength, reflecting Consumers' low-risk, profitable, and regulated utility business model. Consumers is also a significant portion of CMS, reflecting about 95% of the consolidated company.
- There are no cross-default provisions between parent CMS and Consumers that could directly lead to a default at Consumers.

Issue Ratings - Recovery Analysis

- We assign recovery ratings to first-mortgage bonds (FMBs) issued by U.S. utilities, which can result in issue ratings being notched above an issuer credit rating on a utility depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of secured utility bond (SUB) that qualify for a recovery rating as defined in our criteria.
- The recovery methodology is supported by our expectation of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhance recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist.
- Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed an issuer credit rating on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories depending on the calculated ratio.
- Consumers Energy's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Reconciliation

Table 3

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. $)

	--Fiscal year ended Dec. 31, 2018--								
Consumers Energy Co. reported amounts									
	Debt	**Shareholders' equity**	**Revenue**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	6,993.0	6,883.0	6,464.0	1,986.0	1,065.0	289.0	2,151.9	1,449.0	1,822.0
S&P Global Ratings' adjustments									
Cash taxes paid	--	--	--	--	--	--	(156.0)	--	--
Cash taxes paid: Other	--	--	--	--	--	--	--	--	--
Cash interest paid	--	--	--	--	--	--	(287.0)	--	--
Operating leases	61.8	--	--	14.5	3.7	3.7	(3.7)	10.8	--
Postretirement benefit obligations/deferred compensation	136.7	--	--	(82.0)	(82.0)	--	--	--	--
Accessible cash and liquid investments	(39.0)	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	3.0	(3.0)	(3.0)	(3.0)
Share-based compensation expense	--	--	--	16.0	--	--	--	--	--
Securitized stranded costs	(277.0)	--	(33.9)	(33.9)	(8.9)	(8.9)	8.9	(25.0)	--
Power purchase agreements	657.6	--	--	147.3	46.0	46.0	(46.0)	101.3	101.3
Asset retirement obligations	338.1	--	--	22.0	22.0	22.0	--	--	--
Nonoperating income (expense)	--	--	--	--	(12.0)	--	--	--	--
Noncontrolling interest/minority interest	--	37.0	--	--	--	--	--	--	--
Debt: Other	(97.0)	--	--	--	--	--	--	--	--
EBITDA: Other	--	--	--	82.0	82.0	--	--	--	--
Total adjustments	781.2	37.0	(33.9)	165.9	50.9	65.9	(486.9)	84.1	98.3
S&P Global Ratings' adjusted amounts									
	Debt	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	7,774.2	6,920.0	6,430.1	2,151.9	1,115.9	354.9	1,665.1	1,533.1	1,920.3

Source: S&P Global Ratings.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** bbb+
- **Entity status within group:** Insulated (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- General Criteria: Hybrid Capital: Methodology And Assumptions, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013

- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of January 29, 2020)*

Consumers Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Issuer Credit Ratings History	
30-Oct-2019	A-/Stable/A-2
03-Dec-2014	BBB+/Stable/A-2
11-Sep-2014	BBB/Positive/A-2
Related Entities	
CMS Energy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Junior Subordinated	BBB-
Senior Unsecured	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
10 May 2021

Update

Rate this Research

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	Baa1
Type	Pref. Stock - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Consumers Energy Company

Update following downgrade to A1 secured

Summary

Consumers Energy Company's (Consumers Energy) credit reflects its operating profile as a vertically integrated electric and gas utility in a credit supportive regulatory environment in Michigan. Historically, Consumers Energy had produced strong and consistent credit metrics, including a cash flow from operations before working capital (CFO pre-WC) to debt ratio in the mid-20% range. However, metrics began to weaken slightly starting in 2018 primarily due to the gradual erosion in its allowed return on equity (ROE) and equity capitalization through rate case outcomes. In addition, tax reform had a negative impact on its credit metrics. By 2019, CFO pre-WC to debt for Consumers Energy had fallen to about 20%.

Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). CMS has made progress in reducing consolidated leverage as well as the percentage of parent debt in its capital structure, although it remains around 30% of total consolidated debt. All of Consumers' outstanding debt obligations are secured.

Recent developments

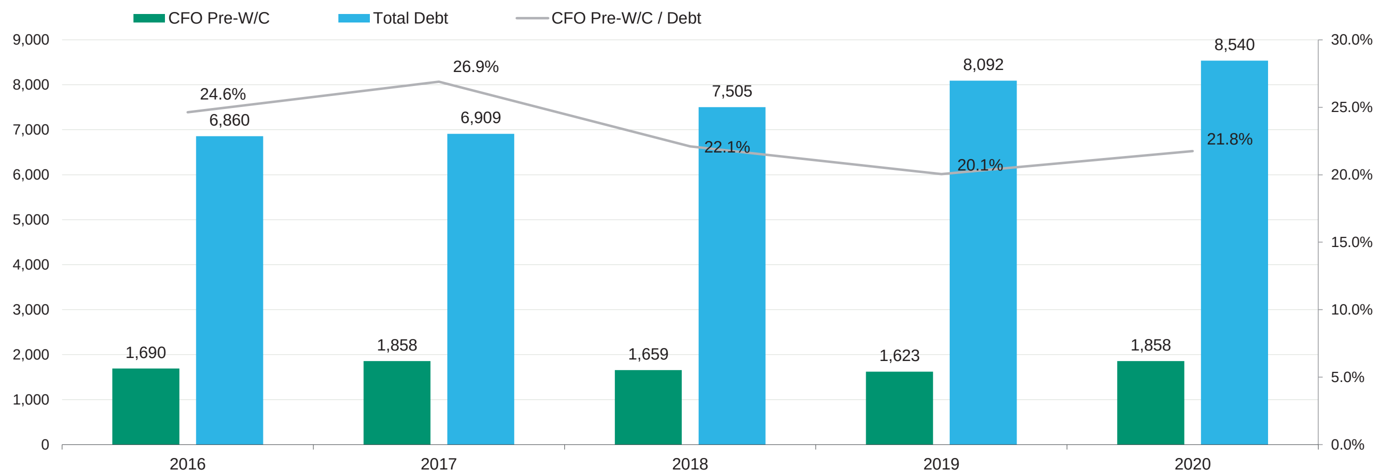
On 3 May 2021, we downgraded the ratings of Consumers Energy due to its weakened credit metrics. Although the regulatory environment in Michigan remains relatively credit supportive, the outcome of recent rate cases has put pressure on its credit metric ratios and we do not expect the ratios to recover back to historical levels.

In the latest electric rate case, the Michigan Public Service Commission (MPSC) authorized a 9.9% ROE and 51.1% equity capitalization. In the previous electric rate case, which was settled and approved in January 2019, the stated ROE was 10% and the assumed capital structure included a 52.5% equity capitalization. Considering both the continued robust utility investment program totaling over $13 billion over the next five years and the lower ROE and equity capitalization, we expect Consumers Energy to produce a CFO pre-WC to debt ratio of around 20% over the next 2-3 years.

The rapid spread of the coronavirus outbreak, severe global economic shock, low oil prices, and asset price volatility are creating a severe and extensive credit shock across many sectors, regions and markets. The combined credit effects of these developments are unprecedented. We regard the coronavirus outbreak as a social risk under our ESG framework, given the substantial implications for public health and safety.

We expect Consumers Energy to be relatively resilient to recessionary pressures because of its rate regulated utility business. We continue to monitor changes in customers' usage, utility bill payment delinquency, and the regulatory response to counter these effects on earnings and cash flow. We see these issues as temporary and not reflective of the core operations or long-term financial or credit profile of Consumers Energy.

Exhibit
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



Source: Moody's Financial Metrics

Credit strengths

» Credit supportive regulation despite financial pressure from recent rate case outcomes

» Regulatory framework provides transparency and timely cost recovery

Credit challenges

» Weakened financial metrics compared to historical levels

» Maintaining continued regulatory support amid a robust capital investment program

» High leverage at the parent company

Rating outlook

The stable outlook reflects our expectation that financial metrics will remain at current levels and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. The stable outlook also incorporates our view that Consumers Energy will maintain prudent financial policies while managing through its robust investment cycle and that debt levels at either the parent or utility will not increase materially.

Factors that could lead to an upgrade

A rating upgrade could be considered if credit metrics improve such that CFO pre-WC to debt is above 21% on a sustained basis. In addition, if the Michigan regulatory framework becomes even more formulaic, transparent or timely with its suite of recovery mechanisms for Consumers Energy, a rating upgrade could be possible.

Factors that could lead to a downgrade

A rating downgrade could be considered if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment; or if the CFO pre-WC to debt ratio declines below 18% on a sustained basis.

Key indicators

Exhibit 2
Consumers Energy Company Key Indicators

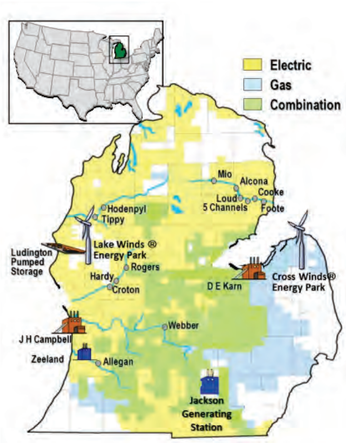
	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20
CFO Pre-W/C + Interest / Interest	6.9x	7.2x	6.3x	6.2x	6.6x
CFO Pre-W/C / Debt	24.6%	26.9%	22.1%	20.1%	21.8%
CFO Pre-W/C – Dividends / Debt	17.4%	19.3%	15.0%	12.7%	14.3%
Debt / Capitalization	43.4%	46.1%	46.4%	46.0%	44.5%

All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Consumers Energy Company (Consumers Energy) is a vertically integrated electric and gas utility serving approximately 6.8 million customers in the state of Michigan with a rate base of approximately $20 billion. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. Consumers Energy is the primary subsidiary of CMS Energy Corporation (CMS), representing over 90% of its consolidated operating revenue. In addition to Consumers Energy, CMS owns approximately 1,838 gross MW of unregulated, primarily natural gas-fired, generation located mostly within Michigan, and EnerBank, a FDIC-insured industrial bank providing unsecured consumer installment loans for financing home improvements. These businesses contribute modestly to consolidated results, and do not materially increase CMS's consolidated business risk profile.

Exhibit 3
Consumers Energy's Service Territory



Source: Company Presentations

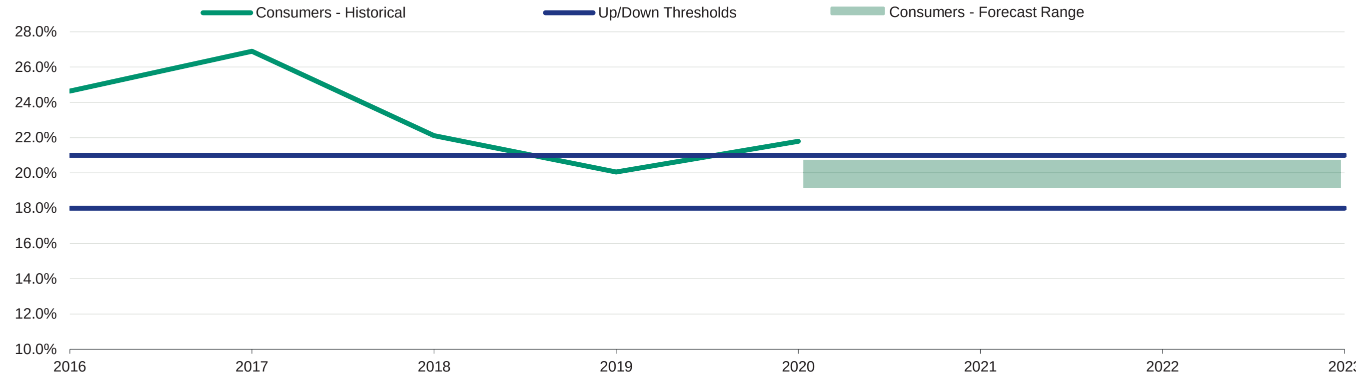
Detailed credit considerations

Weak credit metrics expected through high capital investment cycle

Consumers Energy had historically maintained strong financial metrics with its CFO pre-WC to debt in the mid-20% range. However, metrics began to weaken starting in 2018 primarily due a gradually declining ROE and a lower regulatory equity capital structure. Also, tax reform and an elevated capital expenditure program added downward pressure on the company's credit metric ratios. By 2019, the utility's CFO pre-WC to debt had fallen closer to 20%, reducing financial flexibility.

Consumers' capital program has increased from about $1.2 billion in 2012 to about $2.3 billion in 2020 and, as noted below, is expected to remain elevated. As of year-end 2020, CFO pre-WC to debt was weaker than its 3-year average CFO pre-WC to debt realized between 2017 and 2019. Considering both the continued robust utility investment program totaling over $13 billion over the next five years and the lower ROE and equity capitalization, we expect Consumers Energy to maintain these lower CFO pre-WC to debt ratios of around 20% over the next 2-3 years.

Exhibit 4
Consumers Energy Historical and Projected CFO pre-WC to Debt

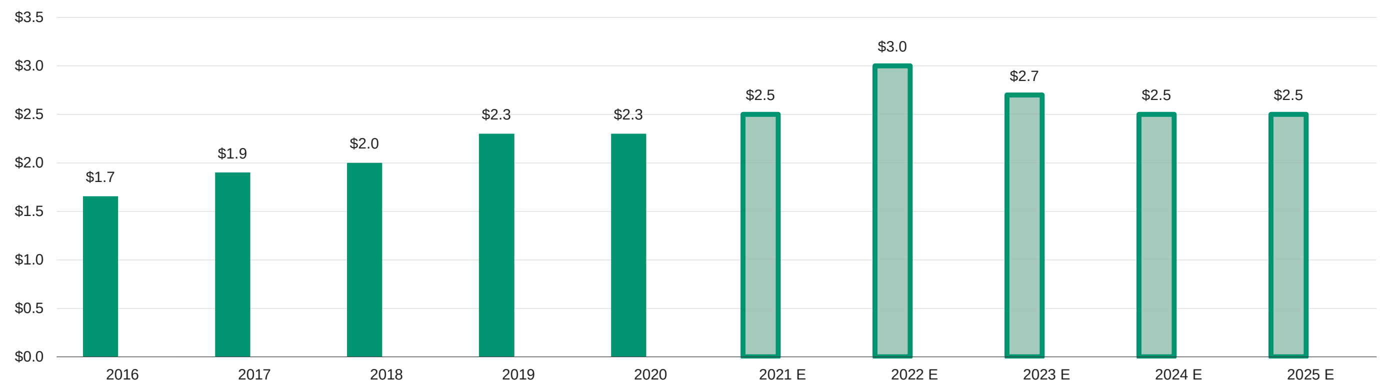


The up/down financial metric thresholds represent one of several factors that could result in an upgrade or downgrade of the rating if the metric is sustained above or below those levels.
Source: Moody's Financial Metrics and Estimates

Capital spending remains elevated

Consumers Energy is currently in the midst of a large capital investment plan and expects to spend approximately $13 billion from 2021 to 2025. The magnitude of the plan, which is intended to improve reliability and efficiency while moving the company to a less carbon intensive future, will require continued regulatory support in order to maintain the company's current financial profile. In 2021, projected investments are approximately $2.5 billion compared to around $2.3 billion in 2020, $2.3 billion in 2019, and $2.0 billion in 2018.

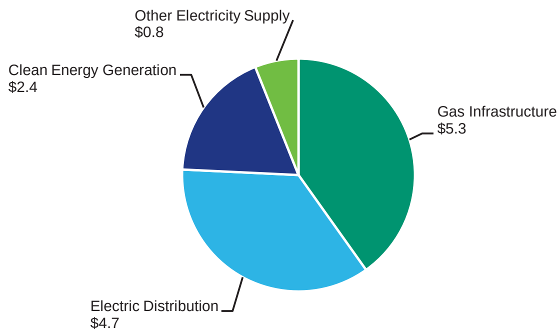
Exhibit 5
Consumers Energy's elevated capital program will extend through 2025
$ billions



Source: Company Investor Presentation

Over the 2021-2025 period, projected capital investments will include maintenance capital of about $10 billion (approximately $4.7 billion for electric operations and $5.3 billion for gas utility operations), and $2.4 billion for clean energy generation and $800 million for other electric supply needed to comply with state and federal laws and regulations. Consumers Energy's goal to keep rate increases modest should help to maintain regulatory support for the recovery of this spending. Funding for these forecasted investments will be provided by internally generated cash flow, the issuance of debt at Consumers and equity contributions from CMS.

Exhibit 6
Planned Capital Expenditures 2021 - 2025
$ billions



Source: Company 10K

Credit supportive regulatory environment despite financial pressure from rate case outcomes

Consumers Energy is regulated in Michigan by the MPSC, which has a regulatory framework that we view to be more credit supportive than most other states. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework was streamlined, improving both the rate case process and the timeliness of cost recovery. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which had already included pre-construction approval for large generating resources, into an integrated resource planning (IRP) process. The IRP process considers a wide range of factors including fuel cost, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before constructing major projects. The legislation also lowered the threshold for major projects to $100 million from $500 million.

In June 2019, the MSPC approved Consumers Energy's latest IRP, which included a plan to reduce its carbon emissions by more than 90% from its 2005 levels by 2040. The plan included the retirement of the 503 MW Karn coal plant by 2023. Also, under Consumers Energy's renewable energy plan, the MPSC has approved the acquisition of up to 525 MW of new wind generation projects and authorized the utility to earn a 10.7% ROE on any projects approved by the MPSC. Also, the MPSC approved a 20-year Purchase Power Agreement (PPA) under which Consumers will purchase 100 MW of renewable capacity, energy and renewable energy credits from a 149 MW solar generating facility in Michigan, which is expected to be operational in 2022. The company plans to file its next IRP in June 2021, which will focus further on accelerating decarbonization, as well as maintaining grid reliability and resilience.

While Michigan's electricity restructuring had initially contemplated full competition in generation, the 2008 legislation limited the number of customers able to choose an alternative supplier at 10% of the prior year load in the utility's service territory. The December 2016 legislation maintained the 10% retail open access (ROA) limit but also provided the possibility for a periodic downward adjustments if ROA demand is below the 10% cap. The 2016 legislation also required, for the first time, that competitive retail suppliers demonstrate adequacy of electric supply for a multi-year period.

Timeliness of cost recovery based on a prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous formulaic rate adjustment mechanisms that provide a high degree of cash flow stability and assurance of recovery. For example, Consumers Energy has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/under recoveries, although interim gas inventory buildup could substantially increase the company's working capital financing when gas prices sharply increase.

Gas utilities in the state also benefit from revenue decoupling mechanisms (RDM) and programs designed to assure recovery of needed infrastructure improvements. Consumers Energy's RDM compares and adjusts for differences between weather normalized actual and authorized revenues. Consumers Energy's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing approximately 540 miles of cast iron pipe and other high-risk components. Consumers currently projects that it will spend about $100 million per year under the EIRP. These expenditures are recoverable through base rates.

Financial pressure from recent rate case outcomes

Consumers maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. The utility currently has an electric rate case pending.

Consumers' last electric rate case was completed in December 2020. The MPSC approved a $90 million electric rate increase based on a 9.9% ROE and 51.1% equity layer. The order also approved the recovery of $12.6 million related to investment in the distribution system. While we had expected the commission to maintain the 10% authorized ROE, we recognize the downward pressure on the ROE due to low Treasury rates.

In March 2021, Consumers filed an electric rate case application with the MPSC seeking a $225 million annual increase, based on a 10.5% ROE and 52% equity layer. The company also requested recovery of $121 million of new infrastructure investments related to the 2019 IRP, distribution system reliability and technology enhancements. We expect the rate case to conclude by the end of the year. If the rate case results in another decrease in both ROE and equity layer, we expect the utility's already weakened metrics to be further pressured.

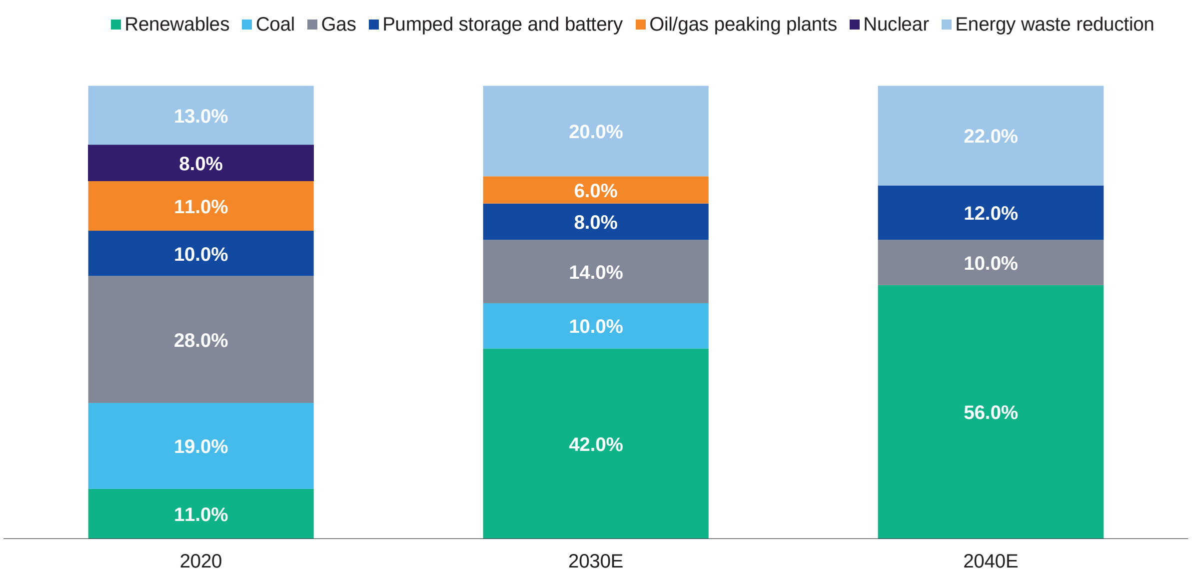
Consumers’ latest gas rate case was settled in September 2020. The MPSC authorized a $144 million revenue increase, 9.9% ROE, 52.05% equity layer (both unchanged from the previous rate case), and continuation of a revenue decoupling mechanism. The company’s rate base valuation was $7.42 billion. As part of the settlement agreement, Consumers agreed not to file its next gas rate case until 1 December 2021. Between 1 October 2021 and 30 September 2022, the company will accelerate the amortization of tax liabilities in an amount forecasted to be approximately $84.5 million.

ESG considerations

Environmental

CMS is strongly positioned for the carbon transition with strategies and plans in place that substantially mitigate its carbon transition exposure. Consumers is currently in a transition to phase out its coal-fired generation and targets a reduction in its CO_2 emissions by more than 90% from its 2005 levels by 2040. Michigan's regulatory framework supports the utility's transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Exhibit 7
Clean Energy Plan Electric Capacity by Fuel Source (MW)

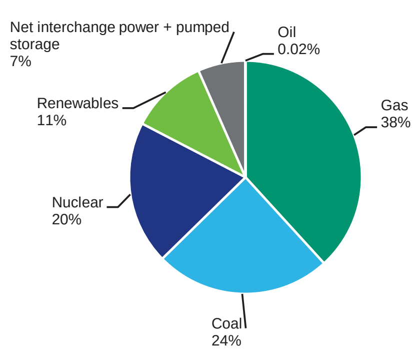


Source: Company filings

In June 2018, Consumers Energy filed its first ever IRP with the MPSC pursuant to the 2016 energy law, in accordance with requirements laid out in the legislation. The IRP was approved by the MPSC in June 2019. The IRP outlined a series of steps the company will take to reach its goal of a 90% carbon emissions reduction and to eliminate its use of coal generation by 2040. The combination and timeline of these programs are aimed at ensuring that the energy it provides remains reliable and affordable over the long-term.

Among the steps outlined in the plan is the termination of its PPA with the Palisades Nuclear Power Plant as well as the closing of units 1 and 2 (503 MW) of the Karn coal-fired plant and replacing it with 525 MW of wind and solar generation. The wind generation capacity addition has been approved by the commission through the Renewable Energy Plan. The IRP also included Consumers Energy's intention to fully exit coal generation by 2040 by closing all three units (1.3 GW) of the J.H. Campbell coal-fired plant. This capacity will be replaced over the next two decades with 5 GW of new solar generation by 2030 and an additional 1 GW by 2040. Even before the approval of the IRP, Consumers had been actively reducing its carbon footprint and moving toward more energy efficient, cleaner generating resources. Consumers' generating capacity has shifted from 41% coal in 2005 to 24% in 2020.

Exhibit 8
2020 Owned and Purchased Generation Supply
GWh



Source: Company filings

In 2020, over half of Consumers Energy's electric generation was provided through long-term power purchase agreements (PPAs) or market purchases. The majority of this production came from two PPAs, one with the 1,240 MW MCV gas-fired facility (approximately 16% of 2020 electric supply) that terminates in March 2025 and a second with the 813 MW Palisades nuclear facility (approximately 10% of 2020 electric supply) that is scheduled to terminate in 2022. The Palisades PPA is not expected to be renewed when it expires, while the company proposed to extend the MCV PPA for another five years in its IRP, albeit at a lower price. We expect that the utility will replace any ensuing energy and capacity shortfall with a mix of renewable generation and demand side management initiatives.

Michigan state statutes allow utilities to securitize related regulatory assets and stranded costs and the MPSC has a history of approving securitization bonds. Most recently, in 2020, the MPSC issued a securitization financing order to authorize Consumers to issue securitization bonds in order to finance the recovery of the remaining book value of Karn units 1 and 2, which are expected to retire in 2023. Prior to this in 2013, the MPSC authorized Consumers Energy's issuance of securitization bonds to finance the recovery of the remaining book value of seven smaller coal-fired electric generating plants that were retired in April 2016 and three smaller natural gas-fired units that were retired in June 2015. Approximately $378 million of securitization bonds were issued through a securitization subsidiary in 2014. Principal and interest payments are made semi-annually through the maturity of the bonds in 2029. We expect similar regulatory treatment would be possible for other future plant retirements.

Social

Social risks are primarily related to Consumers Energy's customer and regulatory relations as well as demographic and societal trends. Consumers Energy's regulatory environment as well as its interaction with the MPSC are important in considering the utility's social risk. Also, the safety and reliability of its operations are extremely important social considerations. Given recent developments related to the COVID-19 pandemic, there is a possibility of increasing social risk, should unemployment remain high, making customers less able to absorb rate increases.

Governance

As a subsidiary of CMS, corporate governance considerations include the financial policy and risk management of its parent company. We note that a stable financial position is an important characteristic for managing environmental and social risks.

Liquidity analysis

We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumers Energy has access to an $850 million secured revolving credit facility expiring in June 2023 and as of 31 December 2020, its net availability was $843 million after having $7 million letters of credit outstanding. The facility includes a sustainability linked pricing metric, which permits an interest rate reduction for meeting targets related to environmental sustainability, specifically renewable generation, and highlights its commitment to shifting its exposure to a greater renewable content. Consumers Energy also maintains a $250 million secured credit facility terminating in November 2022. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's $500 million commercial paper program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at less than 65%. At the period ending 31 December 2020, debt to capital was 49%.

As of 31 December 2020, Consumers had no commercial paper outstanding under its CP program, no borrowings under its various credit facilities and $38 million of letters of credit outstanding on a consolidated basis. In September and December 2020, Consumers redeemed its $375 million first mortgage bond due in 2022 and its $300 million term loan facility due in January 2021, respectively.

The utility’s continuing capital expenditure program and dividend policy result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent.

For the last twelve months ended 31 December 2020, Consumers generated approximately $1.2 billion of cash from operations (CFO), invested $2.2 billion in capital investments and distributed $639 million in dividend payments to CMS, resulting in negative free cash flow (FCF) of approximately $1.6 billion that was offset by parent contributions of $650 million and incremental long-term debt. Consumers' policy is to grow its dividend with earnings, maintaining a payout ratio in the 80% range.

Structural considerations

Consumer Energy's strong stand-alone financial performance has been pressured by significant debt at CMS, the parent company. As of year-end 2020, CMS had approximately $7 billion of consolidated debt outside of Consumers Energy, or approximately 46% of its consolidated total reported debt. Of this amount, approximately $2.8 billion represented deposits of EnerBank, an insured industrial bank wholly owned by CMS, and is supported by approximately $2.8 billion of notes receivable. Excluding self-funding EnerBank, we estimate that CMS's parent level debt to be approximately $4.2 billion or about 34% of the total of Consumers Energy plus pure parent level debt. This still remains as a key driver of the relatively wide differential between the Consumers Energy and CMS credit profiles.

Rating methodology and scorecard factors

Exhibit 9
Methodology Scoring Factors
Consumers Energy Company

Regulated Electric and Gas Utilities Industry [1][2]	Current FY 12/31/2020		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.4x	Aa	6.8x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	21.3%	Baa	19% - 21%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	14.0%	Baa	12% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	45.6%	Baa	44% - 46%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		A2		A2
b) Actual Rating Assigned		A1*		A1*

* Senior Secured Rating.
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 12/31/2020.
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 0

Cash Flow and Credit Metrics

CF Metrics	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20
s ste					
FFO	**1,739**	**1,825**	**1,760**	**1,752**	**1,994**
+/- Ot er	-49	33	-101	-129	-136
CFO Pre-WC	**1,690**	**1,858**	**1,659**	**1,623**	**1,858**
+/- ΔWC	64	-65	1	-15	25
CFO	**1,754**	**1,793**	**1,660**	**1,608**	**1,883**
- Di	500	523	532	593	638
- Capex	1 673	1 649	1 834	2 100	2 184
FCF	**-419**	**-379**	**-706**	**-1,085**	**-939**
CFO Pre-W/C / Debt	24.6%	26.9%	22.1%	20.1%	21.8%
CFO Pre-W/C - Di i en s / Debt	17.4%	19.3%	15.0%	12.7%	14.3%
FFO / Debt	25.4%	26.4%	23.5%	21.6%	23.3%
CF / Debt	18.1%	18.9%	16.4%	14.3%	15.9%
e en e	6 064	6 222	6 464	6 376	6 189
Interest xpense	288	298	315	312	332
et Inco e	615	634	527	725	799
otal ssets	20 026	21 179	22 096	23 699	25 399
otal iabilities	14 139	14 746	15 251	16 053	16 862
otal it	5 888	6 434	6 845	7 647	8 538

All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 1

Peer Comparison Table

	Consumers Energy Company A1 (Stable)			DTE Electric Company (P)A2 (Stable)			DTE Gas Company A3 (Stable)			Northern States Power Company (Minnesota) A2 (Stable)			Wisconsin Power and Light Company A3 (Stable)		
(In US millions)	Dec-18	FYE Dec-19	FYE Dec-20	FYE Dec-18	FYE Dec-19	FYE Dec-20	FYE Dec-18	FYE Dec-19	FYE Dec-20	FYE Dec-19	FYE Dec-19	FYE Dec-20	FYE Dec-18	FYE Dec-19	FYE Dec-20
Revenue	6,464	6,376	6,189	5,298	5,224	5,506	1,415	1,462	1,396	5,122	5,112	5,101	1,453	1,476	1,395
CFO Pre-W/C	1,659	1,623	1,858	1,833	1,791	2,051	337	368	409	1,355	1,362	1,345	446	425	475
Total Debt	7,505	8,092	8,540	7,641	8,495	9,154	1,826	1,997	2,168	5,414	6,363	6,703	2,175	2,328	2,596
CFO Pre-W/C + Interest / Interest	6.3x	6.2x	6.6x	6.8x	6.3x	6.9x	5.5x	5.5x	6.0x	6.7x	6.5x	6.5x	6.5x	6.6x	6.5x
CFO Pre-W/C / Debt	22.1%	20.1%	21.8%	24.0%	21.1%	22.4%	18.5%	18.4%	18.9%	25.0%	21.4%	20.1%	20.5%	18.2%	18.3%
CFO Pre-W/C – Dividends / Debt	15.0%	12.7%	14.3%	18.0%	15.3%	16.5%	12.3%	12.3%	12.6%	16.6%	14.1%	14.0%	14.1%	12.1%	12.1%
Debt / Capitalization	46.4%	46.0%	44.5%	46.0%	47.2%	46.4%	43.9%	44.2%	43.9%	43.0%	45.0%	43.8%	44.6%	44.0%	45.0%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End.
Source: Moody's Financial Metrics

Ratings

Exhibit 12

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Bkd Senior Secured	A1
Pref. Stock	Baa1
Commercial Paper	P-2
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3

Source: Moody's Investors Service

REPORT NUMBER 1281164

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
7 July 2020

Update

Rate this Research

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	A3
Type	Pref. Stock - Dom Curr
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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CLIENT SERVICES

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Consumers Energy Company

Update following negative outlook

Summary

Consumers Energy Company's (Consumers Energy) credit reflects its operating profile as a vertically integrated electric and gas utility in a credit supportive regulatory environment in Michigan. Historically, Consumers Energy had produced strong and consistent credit metrics, including a cash flow from operations before working capital (CFO pre-WC) to debt ratio averaging around 24% through 2018. However, metrics began to weaken slightly starting in 2018 primarily due to tax reform. By 2019, CFO pre-WC to debt for Consumers Energy had fallen to about 20%. With the added pressure of a potentially declining ROE and, more important, a lower regulatory equity capital structure, the credit metrics of Consumers Energy could continue to be pressured. Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa1 stable). However, CMS has made progress in reducing consolidated leverage as well as the percentage of parent debt in its capital structure. All of Consumers' outstanding debt obligations are secured.

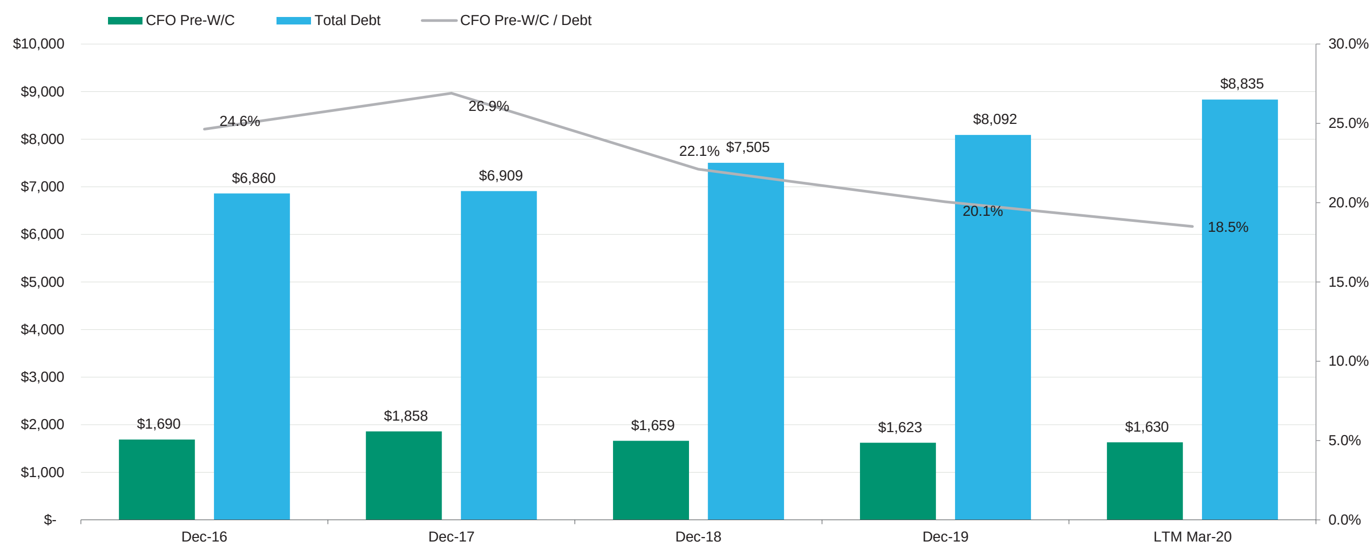
Consumers Energy has been filing for rate cases annually over the last five years, except for in 2019 when it did not file for the electric rate case. In February 2020, the utility filed its latest electric rate case with the Michigan Public Service Commission (MPSC), requesting a $244 million rate increase and a return on equity (ROE) and equity layer of 10.5% and 52.5%, respectively. The filing requests recovery of new investment in distribution system reliability and technology enhancements. In June 2020, the MSPC Staff recommended a 9.75% ROE and 51.1% equity layer. Consumers Energy's previous rate case was settled with a 10% ROE, but other parameters were not disclosed. Consumers Energy also has a gas rate case pending, which it filed in December 2019, with the largest component of the request related to infrastructure investments and related costs.

Recent developments

The rapid spread of the coronavirus outbreak, severe global economic shock, low oil prices, and asset price volatility are creating a severe and extensive credit shock across many sectors, regions and markets. The combined credit effects of these developments are unprecedented. We regard the coronavirus as a social risk under our ESG framework, given the substantial implications for public health and safety. As events related to the coronavirus unfold, we are taking into consideration a wider range of potential outcomes, including more severe downside scenarios. The effects of the pandemic could result in financial metrics that are temporarily weaker than expected.

We expect Consumers Energy to be relatively resilient to recessionary pressures because of its rate regulated utility business. Consumers Energy initially experienced approximately 20-25% lower sales volume from commercial and industrial customers, higher uncollectible accounts, and new quarantine related costs due to the coronavirus. However, its residential sales, which have higher margins, increased materially during the same period, moderating the negative impact on overall electric margins. The MPSC has approved an accounting order to defer bad debt expense for collection in the future. We continue to monitor the changes in customers' usage, utility bill payment delinquency, and the regulatory response to counter these effects on earnings and cash flow. We see these issues as temporary and not reflective of the core operations or long-term financial or credit profile of Consumers Energy.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($MM)



Source: Moody's Financial Metrics

Credit strengths

» Credit supportive regulatory environment

» Regulatory framework provides transparency and timely cost recovery

Credit challenges

» Weakening financial metrics

» Maintaining continued regulatory support amid a robust capital investment program

» High leverage at the parent company

Rating outlook

The negative outlook on Consumers Energy reflects our expectation that its credit metrics are likely to remain weak due to continued pressure on the ROE and equity capital structure. Consumers Energy is likely to produce a CFO pre-WC to debt ratio below 20% if the equity capital structure falls below the current level.

Factors that could lead to an upgrade

The negative outlook limits the likelihood of a near-term rating upgrade. An upgrade could be considered Consumers Energy if its financial metrics improve such that the CFO pre-WC to debt ratio is above 25% on a sustained basis. If the regulatory environment in Michigan improves further such that it becomes more formulaic or transparent, a rating upgrade could be possible.

Factors that could lead to a downgrade

A rating downgrade could be considered for Consumers Energy if there is material deterioration in the Michigan regulatory support; if the utility's authorized ROE or equity capital structure continued to be under pressure; or if the credit profile deteriorates such that CFO pre-WC to debt is below 20%.

Key indicators

Exhibit 2
Consumers Energy Company Key Indicators [1]

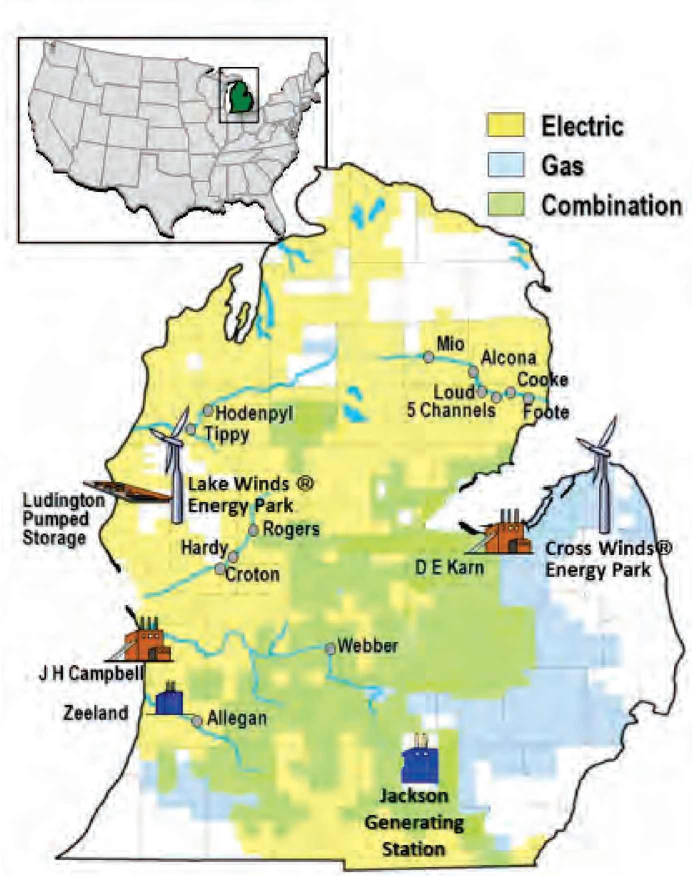
	Dec-16	Dec-17	Dec-18	Dec-19	LTM Mar-20
CFO Pre-W/C + Interest / Interest	6.9x	7.2x	6.3x	6.2x	6.1x
CFO Pre-W/C / Debt	24.6%	26.9%	22.1%	20.1%	18.5%
CFO Pre-W/C – Dividends / Debt	17.4%	19.3%	15.0%	12.7%	11.2%
Debt / Capitalization	43.4%	46.1%	46.4%	46.0%	47.1%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Consumers Energy Company (Consumers Energy) is a vertically integrated electric and gas utility serving approximately 6.7 million customers in the state of Michigan with 2019 operating revenue of approximately $6.4 billion. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. Consumers Energy is the primary subsidiary of CMS Energy Corporation (CMS), representing over 90% of its consolidated operating revenue. In addition to Consumers Energy, CMS owns approximately 1,335 gross MW of unregulated, primarily natural gas-fired, generation located mostly within Michigan, and EnerBank, a FDIC-insured industrial bank providing unsecured consumer installment loans for financing home improvements. These businesses contribute modestly to consolidated results, and do not materially increase CMS's consolidated business risk profile.

Exhibit 3
Consumers' Service Territory



Source: Company Presentations

Detailed credit considerations

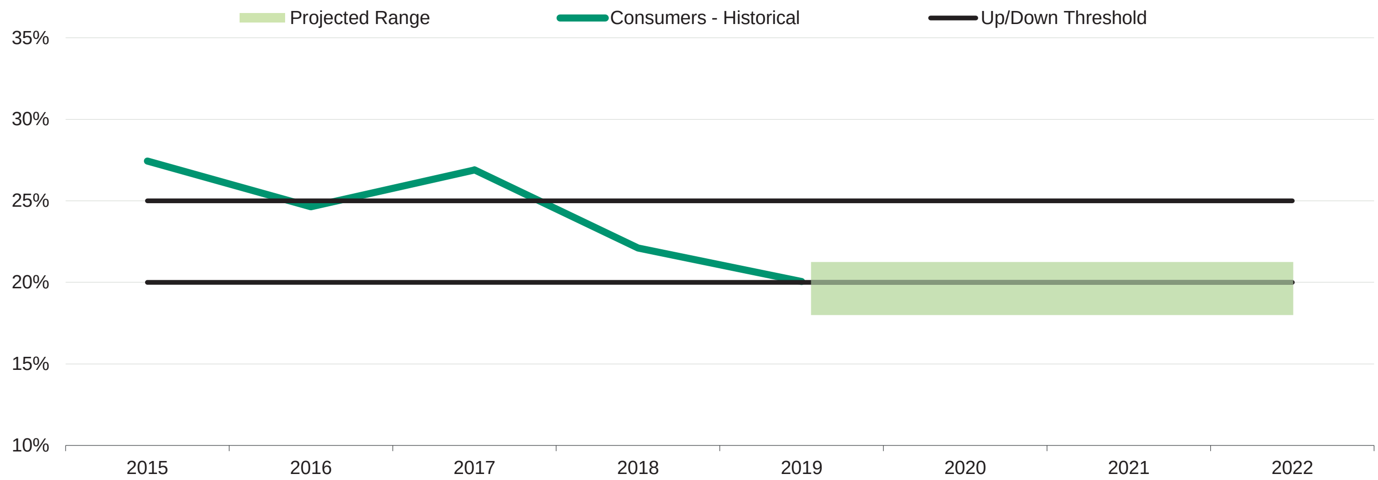
Weak credit metrics expected through high investment cycle

Consumers Energy has historically maintained strong financial metrics with its CFO pre-WC to debt in the mid-20% range. However, metrics began to weaken starting in 2018 primarily due to tax reform and an elevated capital expenditure program. By 2019, the utility's CFO pre-WC to debt had fallen to 20%, reducing financial flexibility. With the potential of a declining ROE and, more important, a lower regulatory equity capital structure resulting from its current rate cases, we expect the credit metrics of Consumers Energy to remain under pressure.

Moreover, it is possible that metrics may temporarily weaken further in 2020 due the negative impact of the COVID pandemic. However, we do not expect the impact to be significant because the utility experienced an increase in residential usage while commercial and industrial customer usage declined. In 2019, residential electric and gas sales generated approximately 60% of Consumers total revenue while commercial and industrial contributed the remainder.

Consumers' capital program increased from about $1.2 billion in 2012 to about $2 billion in 2019 and, as noted below, is expected to remain elevated. The utility's 2019 financial metrics were lower than historical levels due to declining authorized ROE and equity capital structure in addition to the negative tax reform impact. As of the year-end 2019, CFO pre-WC to debt was 20.1%, slightly weaker than the 22.8% 3-year average CFO pre-WC to debt realized between 2017 and 2019. As of LTM 31 March 2020, its CFO pre-WC to debt had fallen to 18.5%. One reason for the higher leverage in 2020 is a prefunding of an upcoming debt maturity to take advantage of the favorable interest rate environment.

Exhibit 4
Consumers Energy Historical and Projected CFO pre-WC to Debt



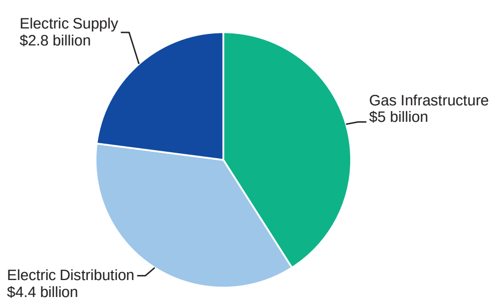
The up/down financial metric thresholds represent one of several factors that could result in an upgrade or downgrade of the rating if the metric is sustained above or below those levels.
Source: Moody's Financial Metrics and Estimates

Capital spending remains elevated

Consumers Energy is currently in the midst of a large capital investment plan and expects to spend approximately $12.2 billion from 2020 to 2024. The magnitude of the plan, which is intended to improve reliability and efficiency while moving the company to a less carbon intensive future, will require continued regulatory support in order to maintain the company's current financial profile. In 2020, projected investments are approximately $2.2 billion compared to around $2 billion in 2019, $1.8 billion in 2018 and $1.6 billion in 2017. Over the 2020-2024 period, projected capital investments will include maintenance capital of about $9.4 billion (approximately $4.4 billion for electric operations and $5 billion for gas utility operations), and $2.8 billion for electric supply projects, including new renewable generation, and environmental investments needed to comply with state and federal laws and regulations.

Consumers Energy's goal to keep rate increases modest should increase the likelihood of continued regulatory support. Funding for these forecasted investments will be provided by internally generated cash flows, the issuance of debt at Consumers' and equity contributions from CMS.

Exhibit 5
Planned Capital Expenditures 2020 - 2024



Source: Company Filings

Credit supportive regulatory environment in Michigan

Consumers Energy is regulated in Michigan by the MPSC, which has a regulatory framework that we view to be more credit supportive than most other states. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework was streamlined, improving both the rate case process and the timeliness of cost recovery. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which already included pre-construction approval for large generating resources, into an integrated resource planning (IRP) process. The IRP process will consider a wide range of factors including fuel cost, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before constructing major projects. The legislation also lowered the threshold for major projects to $100 million from $500 million.

While Michigan's electricity restructuring had initially contemplated full competition in generation, the 2008 legislation limited the number of customers able to choose an alternative supplier at 10% of the prior year load in the utility's service territory. The December 2016 legislation maintained the 10% retail open access (ROA) limit but also provided a possibility for a periodic downward adjustments if ROA demand is below the 10% cap. The 2016 legislation also required, for the first time, that competitive retail suppliers demonstrate adequacy of electric supply for a multi-year period.

In June 2019, the MSPC approved Consumers Energy's latest IRP, which includes a plan to reduce its carbon emissions 90% by 2040 from its 2005 levels. The plan includes the retirement of the 503 MW Karn coal plant by 2023. Also, under Consumers Energy's renewable energy plan, the MPSC has approved the acquisition of up to 525 MW of new wind generation projects and authorized the utility to earn a 10.7% ROE on any projects approved by the MPSC.

Timeliness of cost recovery based on a prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous formulaic rate adjustment mechanisms that provide a high degree of cash flow stability and assurance of recovery. For example, Consumers Energy has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/under recoveries, though interim gas inventory buildup could substantially increase the company's working capital financing when gas prices sharply increase.

Gas utilities in the state also benefit from revenue decoupling mechanisms (RDM) and programs designed to assure recovery of needed infrastructure improvements. Consumers Energy's RDM compares and adjusts for differences between weather normalized actual and authorized revenues. Consumers Energy's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing approximately 540 miles of cast iron pipe and other high-risk components. Consumers currently projects that it will spend about $75 million per year under the EIRP. These expenditures are recoverable through base rates.

Potential pressure from rate case outcomes

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. Currently, the utility has both electric and gas rate cases pending. In its latest gas rate case, the MPSC authorized a 9.9% ROE, slightly below its previously authorized ROE of 10%. While we had expected the commission to maintain the 10% authorized ROE, we recognize the downward pressure on the ROE due to low Treasury rates.

In February 2020, Consumers Energy filed an electric rate case with the MPSC seeking a $244 million annual increase, based on a 10.5% authorized ROE and 52.5% equity layer. The largest component of the request was related to investments is rate base and operating and maintenance costs. The filing requests authority to recover new investment in distribution system reliability and technology enhancements. We expect the rate case to conclude by December 2020. On 24 June, the MSPC Staff recommended a 9.75% ROE and 51.1% equity layer, both below the current levels. If the rate case results in a decrease in both ROE and equity layer, we expect the utility's already weakened metrics to be further pressured.

Consumers Energy's last rate case was completed in January 2019. The MPSC approved a settlement which included a $24 million electric rate decrease. The settlement eliminated the $113 million Tax Cuts and Jobs Act (TCJA) credit to customers and resulted in an $89 million net increase in annual rates. The rate change was premised on a 10% return on equity (ROE). However, other rate case parameters, including the equity layer, were not disclosed.

Consumers also has an open gas rate case pending. In December 2019, Consumers filed a gas rate case application with the MPSC seeking a $245 million annual increase, based on a 10.5% authorized ROE and 52.5% equity layer. In May 2020, the request was revised to approximately $229 million. The largest component of the request was related to infrastructure investment and related costs. The filing also seeks approval for the continuation of a revenue decoupling mechanism. We expect the rate case to conclude by October 2020 based on the 10-month time frame specified in the 2016 legislation. Consumer Energy's last gas rate case was completed in September 2019. The rate increase approved by the MPSC was based on an 9.9% ROE and 52.05% financial equity structure on the rate base valued around $6.43 billion.

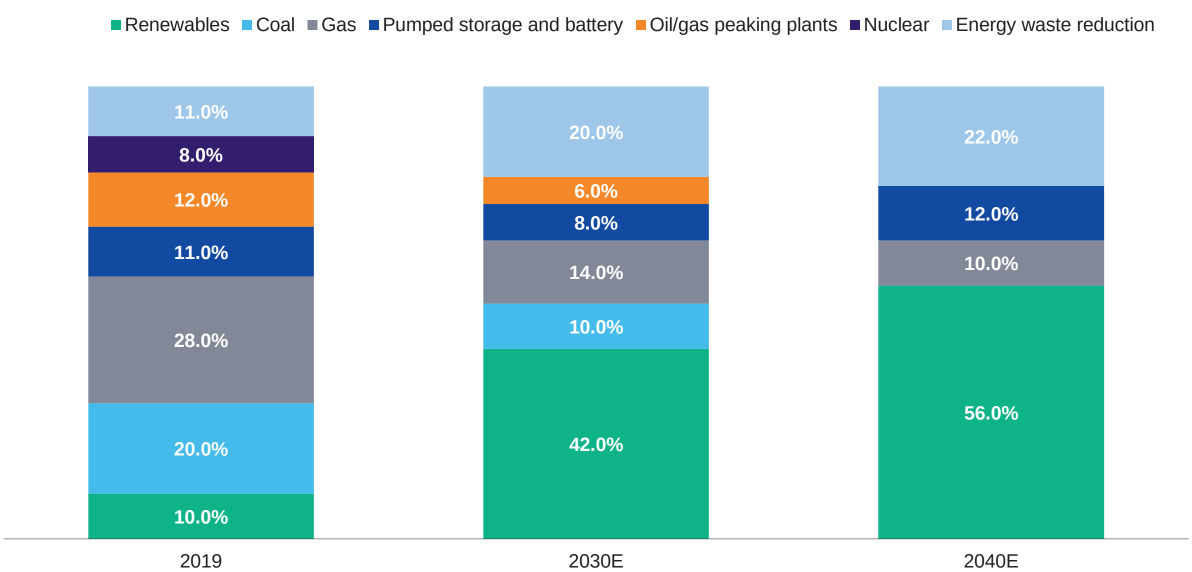
ESG considerations

Environmental

Consumers Energy has elevated carbon transition risk within the US regulated utility sector because it is a vertically integrated utility that has significant fossil based generation capacity. Consumers is currently in a transition to phase out its coal-fired generation and targets a reduction in its CO2 emissions of 90% by 2040 from its 2005 levels. Michigan's regulatory framework supports the utility's transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Exhibit 6

Clean Energy Plan Electric Capacity by Fuel Source (MW)

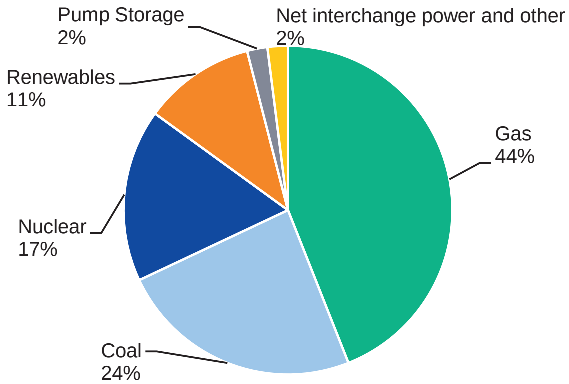


Source: Company filings

In June 2018, Consumers Energy filed its first ever IRP pursuant to the 2016 energy law with the MPSC, in accordance with requirements laid out in the 2016 energy legislation. It was approved by the MPSC in June 2019. The IRP outlined a series of steps the company will take to reach its goal to exceed a 90% carbon emissions reduction and to eliminate its use of coal generation by 2040. Additionally, the plan will allow the utility to achieve a breakthrough goal of at least 50% combined renewable energy and energy efficiency by 2030. The combination and timeline of these programs are aimed at ensuring that the energy it provides remains reliable and affordable over the long-term.

Among the steps outlined in the plan is the termination of its PPA with the Palisades Nuclear Power Plant as well as the closing of units 1 and 2 (503 MW) of the Dan E Karn coal-fired plant and replacing it with 525 MW of wind and solar generation. The wind generation capacity addition has been approved by the commission through the Renewable Energy Plan. The IRP also included Consumers Energy's intention to fully exit coal generation by 2040 by closing all three units (1.4 GW) of the J.H. Campbell coal-fired plant. This capacity will be replaced over the next two decades with 5 GW of new solar generation by 2030 and an additional 1 GW by 2040. Even before the approval of the IRP, Consumers had been actively reducing its carbon footprint and moving toward more energy efficient, cleaner generating resources. Consumers' generating capacity has shifted from 41% coal in 2005 to 24% in 2019.

Exhibit 7
2019 Generation Capacity



Source: Company filings

In 2019, about half of Consumers Energy's electric generation was provided through long-term power purchase agreements or market purchases. The majority of this production came from two power purchase agreements, one with the 1,240 MW MCV gas-fired facility (approximately 17% of 2019 electric supply) that terminates in March 2025, and a second with the 813 MW Palisades nuclear facility (approximately 21% of 2019 electric supply) that is scheduled to terminate in 2022. The Palisades PPA is not expected to be renewed when it expires, while the company is proposing to extend the MCV PPA for another five years in its IRP, albeit at a lower price. We expect that the utility will replace any ensuing energy and capacity shortfall with a mix of renewable generation and demand side management initiatives.

Michigan state statutes allow utilities to securitize restructuring-related regulatory assets and stranded costs and the MPSC has a history of approving securitization bonds. Most recently, in 2013, the MPSC authorized Consumers Energy's issuance of securitization bonds to finance the recovery of the remaining book value of seven smaller coal-fired electric generating plants that were retired in April 2016 and three smaller natural gas-fired units that were retired in June 2015. Approximately $378 million of securitization bonds were issued through a securitization subsidiary in 2014. Principal and interest payments are made semi-annually through the maturity of the bonds in 2029. We expect similar regulatory treatment would be possible for other future plant retirements.

Social

Social risks are primarily related to Consumers Energy's customer and regulatory relations as well as demographic and societal trends. Consumers Energy's regulatory environment as well as its interaction with the MPSC are important in considering the utility's social risk. Also, the safety and reliability of its operation are extremely important social considerations. Given recent developments related to the COVID-19 pandemic, there is a possibility of increasing social risk, should unemployment remain high, making customers less able to absorb rate increases.

Governance

As a subsidiary of CMS, corporate governance considerations include the financial policy and risk management of its parent company. We note that a stable financial position is an important characteristic for managing environmental and social risks.

Liquidity analysis

We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumer Energy has access to an $850 million revolving credit facility expiring in June 2023 and as of 31 March 2020, its net availability was $843 million after having $7 million letters of credit outstanding. The facility includes a sustainability linked pricing metric, which permits an interest rate reduction for meeting targets related to environmental sustainability, specifically renewable generation, and highlights its commitment to shifting its exposure to a greater renewable content. Consumer Energy also maintains a $250 million secured credit facility terminating in November 2021. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's $500 million commercial paper program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at less than 65%. At the period ending 31 March 2020, debt to capital was 49%.

As of 31 March 2020, Consumers had no commercial paper outstanding under its CP program, no borrowings under its various credit facilities and $45 million of letters of credit outstanding. In March and April 2020, Consumers redeemed its $100 million first mortgage bond due in 2020 and $300 million of first mortgage bond due in 2022, respectively.

The utility's continuing capital expenditure program and dividend policy result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent.

For the last twelve months ended 31 March 2020, Consumers generated approximately $1.7 billion of cash from operations (CFO), invested $2.1 billion in capital investments and distributed $640 million in dividend payments to CMS, resulting in a negative free cash flow (FCF) of approximately $1.1 billion that was offset by parent contributions of $675 million and incremental long-term debt. Consumers policy is to grow its dividend with earnings, maintaining a payout ratio in the 80% range.

Structural considerations

Consumer Energy's strong stand-alone financial performance has been pressured by a significant debt level at CMS, the parent company. However, CMS has made slow but steady progress in reducing its consolidated leverage as well as the percentage of parent debt in its capital structure. As of year-end 2019, CMS had approximately $5.8 billion of consolidated debt outside of Consumer Energy, or approximately 44% of its consolidated total reported debt. Of this amount, approximately $2.4 billion represented deposits of EnerBank, an insured industrial bank wholly owned by CMS, and is supported by approximately $2.4 billion of notes receivable. Excluding self-funding EnerBank, we estimate that CMS's parent level debt to be approximately $3.4 billion or about 32% of the total of Consumers Energy plus pure parent level debt. This still remains as a key driver of the relatively wide differential between the Consumers Energy and CMS credit profiles.

Rating methodology and scorecard factors

Rating Factors
Consumers Energy Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2020		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.6x	Aa	6x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	23.1%	A	18% - 22%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.5%	Baa	12% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	45.4%	Baa	44% - 48%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A2		A2
b) Actual Rating Assigned		(P)A2		(P)A2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 03/31/2020 (LTM)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 9

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-16	Dec-17	Dec-18	Dec-19	LTM Mar-20
As Adjusted					
EBITDA	**2,043**	**2,163**	**2,097**	**2,201**	**2,225**
FFO	**1,739**	**1,825**	**1,760**	**1,752**	**1,756**
+/- Other	(49)	33	(101)	(129)	(126)
CFO Pre-WC	**1,690**	**1,858**	**1,659**	**1,623**	**1,630**
+/- ΔWC	64	(65)	1	(15)	67
CFO	**1,754**	**1,793**	**1,660**	**1,608**	**1,697**
- Div	500	523	532	593	640
- Capex	1,673	1,649	1,834	2,100	2,144
FCF	**(419)**	**(379)**	**(706)**	**(1,085)**	**(1,087)**
(CFO Pre-W/C) / Debt	24.6%	26.9%	22.1%	20.1%	18.5%
(CFO Pre-W/C - Dividends) / Debt	17.4%	19.3%	15.0%	12.7%	11.2%
FFO / Debt	25.4%	26.4%	23.5%	21.6%	19.9%
RCF / Debt	18.1%	18.9%	16.4%	14.3%	12.6%
Revenue	6,064	6,222	6,464	6,376	6,177
Cost of Good Sold	2,636	2,696	2,886	2,668	2,483
Interest Expense	288	298	315	312	320
Net Income	615	631	704	742	751
Total Assets	20,026	21,179	22,096	23,699	24,206
Total Liabilities	14,139	14,746	15,251	16,053	16,194
Total Equity	5,888	6,434	6,845	7,647	8,013

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 10

Peer Comparison Table [1]

	Consumers Energy Company (P)A2 Negative			DTE Electric Company (P)A2 Stable			DTE Gas Company A3 Stable			Northern States Power Company (Minnesota) (P)A2 Stable			Wisconsin Power and Light Company A3 Stable		
(in US millions)	FYE Dec-18	FYE Dec-19	LTM Mar-20	FYE Dec-18	FYE Dec-19	LTM Mar-20	FYE Dec-18	FYE Dec-19	LTM Mar-20	FYE Dec-18	FYE Dec-19	LTM Mar-20	FYE Dec-18	FYE Dec-19	LTM Mar-20
Revenue	6,464	6,376	6,177	5,298	5,224	5,201	1,415	1,462	1,358	5,122	5,112	5,012	1,453	1,476	1,436
EBITDA	2,097	2,201	2,225	2,038	2,146	2,119	422	469	428	1,682	1,749	1,740	535	591	586
CFO Pre-W/C / Debt	22.1%	20.1%	18.5%	24.0%	21.1%	20.6%	18.5%	18.4%	18.6%	25.0%	23.4%	23.4%	20.5%	18.2%	18.2%
CFO Pre-W/C – Dividends / Debt	15.0%	12.7%	11.2%	18.0%	15.3%	15.0%	12.3%	12.3%	12.2%	16.6%	15.4%	15.1%	14.1%	12.0%	11.7%
Debt / EBITDA	3.6x	3.7x	4.0x	3.7x	4.0x	4.3x	4.3x	4.3x	4.6x	3.2x	3.3x	3.3x	4.1x	3.9x	4.0x
Debt / Capitalization	46.4%	46.0%	47.1%	46.0%	47.2%	48.8%	43.9%	44.2%	42.6%	43.0%	42.9%	42.8%	44.6%	44.0%	43.3%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics

Ratings

Exhibit 11

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Negative
Sr Sec Bank Credit Facility	Aa3
First Mortgage Bonds	Aa3
Bkd Senior Secured	Aa3
Pref. Stock	A3
Commercial Paper	P-1
PARENT: CMS ENERGY CORPORATION	
Outlook	Negative
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Jr Subordinate	Baa2

Source: Moody's Investors Service

REPORT NUMBER 1232442

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S
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INVESTORS SERVICE

CREDIT OPINION
19 June 2019

Update

Rate this Research

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	(P)A2
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Consumers Energy Company

Update to credit analysis

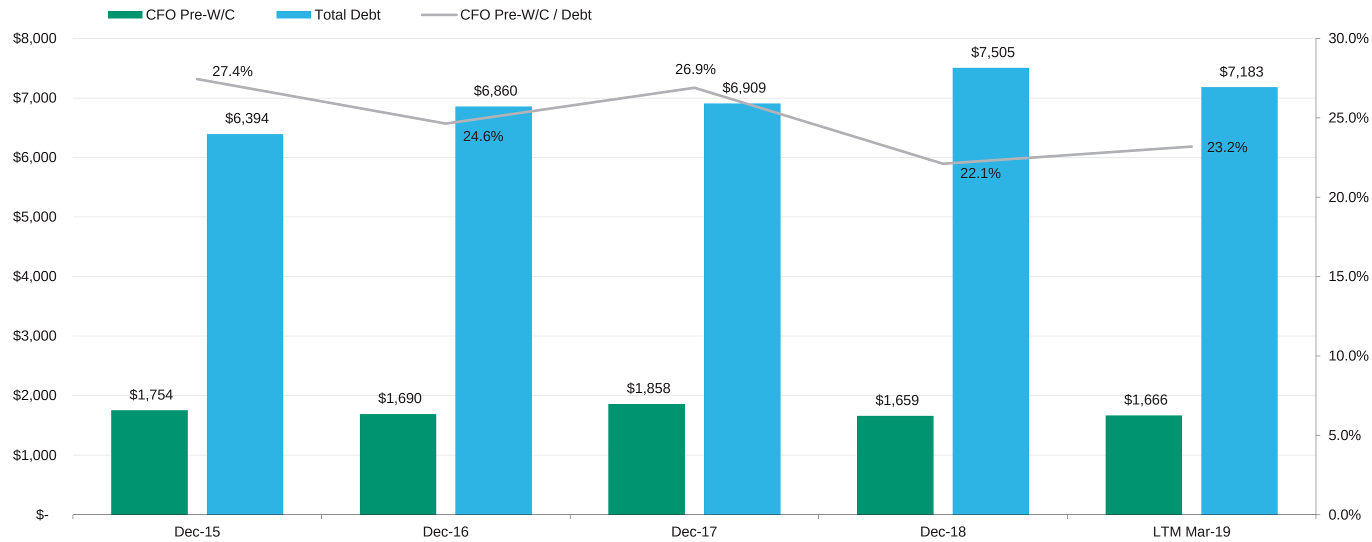
Summary

Consumers Energy Company's (Consumers) credit profile reflects its operations as an integrated electric and gas utility in Michigan. It operates in a regulatory environment that we view to be above average. The regulatory framework in Michigan enhances predictability of cash flows and results in strong credit metrics, even while the utility has been making significant investments into its electric and gas utility systems. We expect the current framework to continue for the foreseeable future. Consumers' strong stand-alone financial performance has historically been pressured by significant debt at its parent company CMS Energy (CMS, Baa1 stable). However, CMS has made progress in reducing its consolidated leverage as well as the percentage of parent debt in its capital structure. All of Consumers' outstanding debt obligations are secured.

In January 2019, Consumers' most recent electric rate case settlement was approved by the Michigan Public Service Commission (MPSC). The final order maintained the same 10% return on equity (ROE) from Consumers' previous rate case but other parameters were not disclosed. The rate case outcome incorporated the change in the marginal corporate tax rate to 21% from 35%, following the passage of federal tax reform. Consumers currently has a gas rate case pending, which it filed in November 2018, with the largest component of the request related to infrastructure investments and related costs.

We expect Consumers to exhibit financial metrics that are appropriate for its overall credit profile although they will be lower than the company's historical metrics. Its cash flow from operations before changes in working capital (CFO pre-WC) to debt is expected to range between 20% and 24% over the next few years. This is primarily due to Consumer's robust capital investment program, and we anticipate that the company's leverage will be maintained at an elevated level.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($MM)



Source: Moody's Financial Metrics

Credit strengths

» Supportive regulatory environment with prescriptive suite of recovery mechanisms

» Financial metrics that are appropriate for its credit profile, despite expected decline

Credit challenges

» High leverage at the parent company

» Pressure to maintain continued regulatory support for its robust investment program

Rating outlook

Consumers' stable outlook reflects our expectation that the Michigan legislative and regulatory environments will remain constructive and allow the utility to recover, and earn a reasonable return on, prudently incurred capital investments such that the utility's financial profile will remains healthy. For example, the stable outlook incorporates our view that the company's CFO pre-WC to debt will be in the low 20% range over the next 12-18 months.

Factors that could lead to an upgrade

Consumers' rating could be upgraded if there is a sustained increase in cash flow or a reduction in leverage, leading to CFO pre-WC to debt meaningfully above 25%. Also, if there is a significant reduction in parent debt, a rating upgrade could be considered. If the Michigan regulatory environment were to become even more formulaic, transparent or timely with its suite of recovery mechanisms, an upgrade could be possible.

Factors that could lead to a downgrade

A rating downgrade could be considered if the regulatory environment in Michigan becomes less constructive or contentious. Also, if there is a deterioration in financial metrics such as CFO pre-WC to debt falling below 20%, or if parent debt increases or credit quality deteriorates significantly, further pressuring Consumers' credit profile, Consumers' rating could be downgraded.

Key indicators

Exhibit 2
Consumers Energy Company [1]

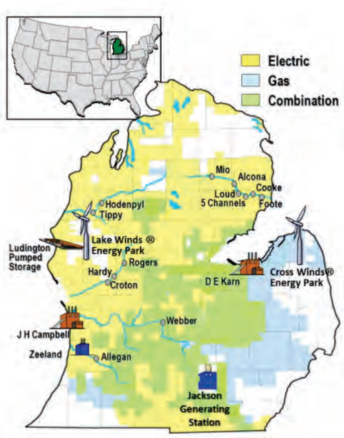
	Dec-15	Dec-16	Dec-17	Dec-18	LTM Mar-19
CFO Pre-W/C + Interest / Interest	7.4x	6.9x	7.2x	6.3x	6.4x
CFO Pre-W/C / Debt	27.4%	24.6%	26.9%	22.1%	23.2%
CFO Pre-W/C – Dividends / Debt	20.0%	17.4%	19.3%	15.0%	15.1%
Debt / Capitalization	43.7%	43.4%	46.1%	46.4%	44.1%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Consumers Energy Company (Consumers) is a vertically integrated electric and gas utility serving approximately 6.7 million customers in the state of Michigan with 2018 operating revenue of approximately $6.5 billion. Consumers' electric operations account for approximately two thirds of its revenue, cash flow and asset base. Consumers is the primary subsidiary of CMS Energy Corporation (CMS), representing about 94% of its consolidated operating revenue. In addition to Consumers, CMS owns approximately 1,304 gross MW of unregulated, primarily natural gas-fired, generation located mostly within Michigan, and EnerBank, a FDIC-insured industrial bank providing unsecured consumer installment loans for financing home improvements. These businesses contribute modestly to consolidated results, and do not materially increase CMS's consolidated business risk profile.

Exhibit 3
Consumers' Service Territory



Source: Company Presentations

Detailed credit considerations

Credit supportive regulatory environment in Michigan

Consumers benefits from an above average regulatory environment within the U.S. in terms of support for its long-term credit quality. Energy legislation enacted by the Michigan legislature in 2008 provided the catalyst for this view as it streamlined the rate case process, reduced regulatory lag, placed a limit on customer participation in electric choice and provided financial support for utility investments. Additional legislation was enacted in 2016 to maintain retail energy markets that are competitive, affordable and reliable as the state transitions to a cleaner energy environment. The new legislation was also supportive of utility's credit quality.

In accordance with the 2016 energy legislation, a forward test year continues to be used in the rate cases. However, the legislation further improved the timeliness of rate cases by requiring a final decision within 10 months of the rate request filing. Rate case decisions were required to be made within twelve months of the filing prior to this legislation. The improvement was to balance the loss of the utilities' ability to implement new rates on an interim basis.

The 2016 legislation also provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which already included pre-construction approval and determination of rate making parameters for large generating resources, by adding an integrated resource planning (IRP) process. The legislation allowed the IRP process to encompass a wide range of factors including fuel cost, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before constructing major projects. The legislation also lowered the CON threshold for major projects to $100 million from $500 million.

While Michigan's electricity restructuring had initially contemplated full competition in generation, the 2008 legislation limited the number of customers able to choose an alternative supplier at 10% of the prior year load in the utility's service territory. The December 2016 legislation maintained the 10% retail open access (ROA) limit but also provided a possibility for periodic downward adjustments if ROA demand is below the 10% cap. The 2016 legislation also requires, for the first time, that competitive retail suppliers demonstrate adequacy of electric supply for a multi-year period.

Timeliness of cost recovery based on prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous formulaic rate adjustment mechanisms that provide a high degree of cash flow stability and assurance of recovery. For example, Consumers has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/under recoveries, though interim gas inventory buildup could substantially increase the company's working capital financing when gas prices sharply increase.

Gas utilities in the state also benefit from revenue decoupling mechanisms (RDM) and programs designed to assure recovery of needed infrastructure improvements. Consumers' RDM compares and adjusts for differences between weather normalized actual and authorized revenues. Consumers' enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing approximately 540 miles of cast iron pipe and other high-risk components. Consumers currently projects that it will spend about $75 million per year under the EIRP. These expenditures are recoverable through base rates.

Reasonable rate case outcomes to continue

Consumers maintains an active regulatory schedule with its electric and gas general rate cases typically filed every year in an alternating pattern. Consumers currently has its gas base rate case open. In November 2018, Consumers filed an application with the MPSC seeking a $229 million annual rate increase, based on a 10.75% authorized ROE. In June 2019, the company revised its requested rate increase to $204 million. The largest component of the revised request was related to infrastructure investment and related costs. The filing also seeks approval for the continuation of a revenue decoupling mechanism. We expect the rate case to conclude by the end of September 2019 based on the 10-month time frame specified in the 2016 legislation.

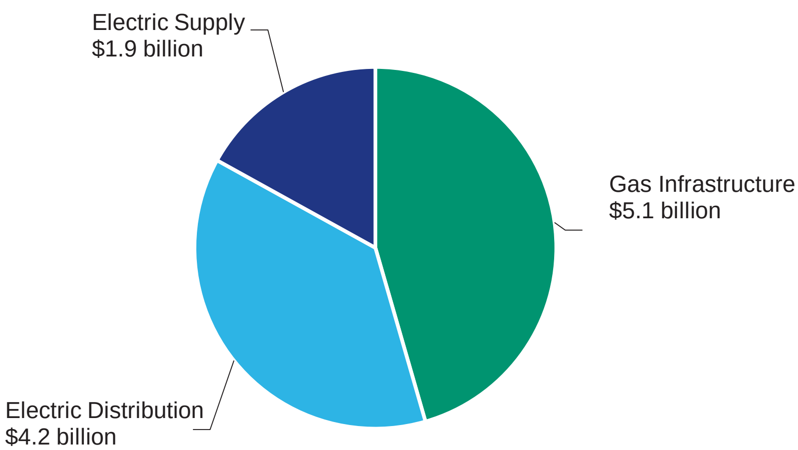
In January 2019, Consumers completed its last electric rate case. The MPSC approved the settlement which included a $24 million electric rate decrease for Consumers. The settlement eliminated the $113 million Tax Cuts and Jobs Act (TCJA) credit to customers and resulted in an $89 million net increase in annual rates. The rate change was premised on a 10% return on equity (ROE). However, other rate case parameters were not disclosed. Overall, we view the rate case outcome as illustrative of the MPSC's continued reasonable regulatory treatment of Consumers. As part of its rate case, Consumers agreed to stay out of rate cases until 2020 as part of the settlement.

Capital spending remains elevated

Consumers' elevated capital investment program is expected to continue for the foreseeable future. The magnitude of the plan, which is intended to improve reliability and efficiency while moving the company to a less carbon intensive future, will require continued regulatory support in order to maintain the company's current financial profile. In 2019, projected investments are approximately $2.2 billion compared to around $1.8 billion in 2018, $1.6 billion in 2017 and $1.7 billion in 2016. Over the 2019-2023 period, the utility has projected $11.2 billion of capital investments which will include maintenance capital of about $9.3 billion (approximately $4.2 billion for electric operations and $5.1 billion for gas utility operations), and $1.9 billion on electric supply projects, representing new generation, including renewable generation, and environmental investments needed to comply with state and federal laws and regulations.

Consumers' aim to keep rate increases modest should increase the likelihood of continued regulatory support. Funding for these forecasted expenditures will be provided by internally generated cash flows, the issuance of debt at Consumers' and equity contributions from CMS.

Exhibit 4
Planned Capital Expenditures 2019 - 2023



Source: Company Filings

Relatively stable financial metrics that are appropriate for its credit profile

Consumers' capital program increased from about $1.2 billion in 2012 to about $1.8 billion in 2018 and, as noted above, is expected to remain elevated and reach roughly $2 billion per year over the next five years. The utility's 2018 financial metrics were lower due to additional leverage. As of the year-end 2018, its CFO pre-WC to debt was about 22%, slightly weaker than the 24.5% 3-year average CFO pre-WC to debt realized between 2016 and 2018. Over the next 12-18 months, its financial results are expected to remain in the low 20% range due to its increased capital expenditure levels and we anticipate negative operating cash flow. However, we expect the company to seek regulatory relief and the regulatory outcomes to be constructive.

Pathway to decarbonization outlined in the company's first ever Integrated Resource Plan

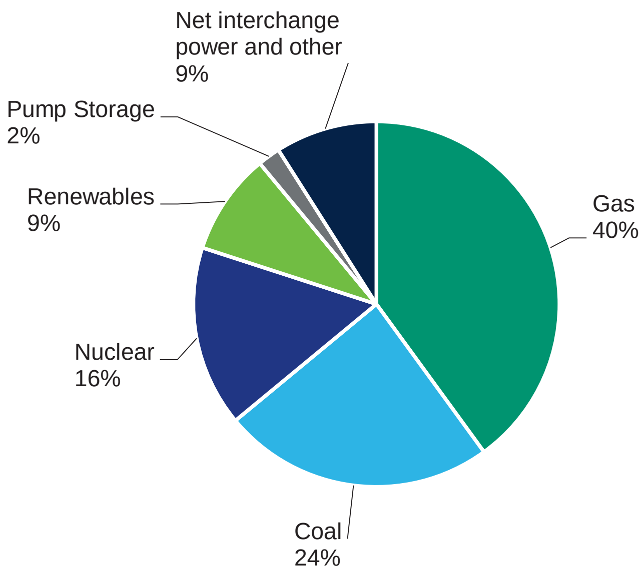
In June 2018, Consumers filed its first ever Integrated Resource Plan (IRP) with the MPSC, in accordance with requirements laid out in the 2016 energy legislation. The IRP outlined a series of steps the company will take to reach its goal to exceed 90% carbon emissions reduction and the elimination of its use of coal generation by 2040. To meet its environmental sustainability goals, Consumers plans to materially increase its renewable energy capacity from 11% to 42% by 2030, and 56% by 2040, and intends to increase its use of energy efficiency and other customer demand management programs. The combination and timeline of these programs are aimed at ensuring that the energy it provides remains reliable and affordable over the long-term.

Consumer's IRP filing was approved by the MPSC in June 2019. Among the steps outlined in the plan is the termination of its PPA with the Palisades Nuclear Power Plant as well as the closing of units 1 and 2 (515 MW) of the Dan E Karn coal-fired plant and replacing it with 525 MW of wind generation. The wind generation capacity addition has already been approved by the commission through the Renewable Energy Plan. The IRP plan also included Consumers intention to fully exit coal generation by 2040 by closing all three units (1.4 GW) of the J.H. Campbell coal-fired plant. This capacity will be replaced over the next two decades with 5 GW of new solar generation by 2030 and an additional 1 GW by 2040. In addition to reducing its carbon emission profile, the approved IRP provided Consumers an earnings adder, termed a "financial compensation mechanism (FCM)" that will allow the company to recover a cost of capital return of 5.88%, the company's current weighted average cost of capital, on top of its PPA prices.

Even before the approval of the IRP, Consumers had been actively reducing its carbon footprint and moving toward more energy efficient, cleaner generating resources. Consumers' generating capacity shifted from 41% coal in 2005 to 24% in 2018.

Exhibit 5

2018 Generation Capacity



Source: Company Filings

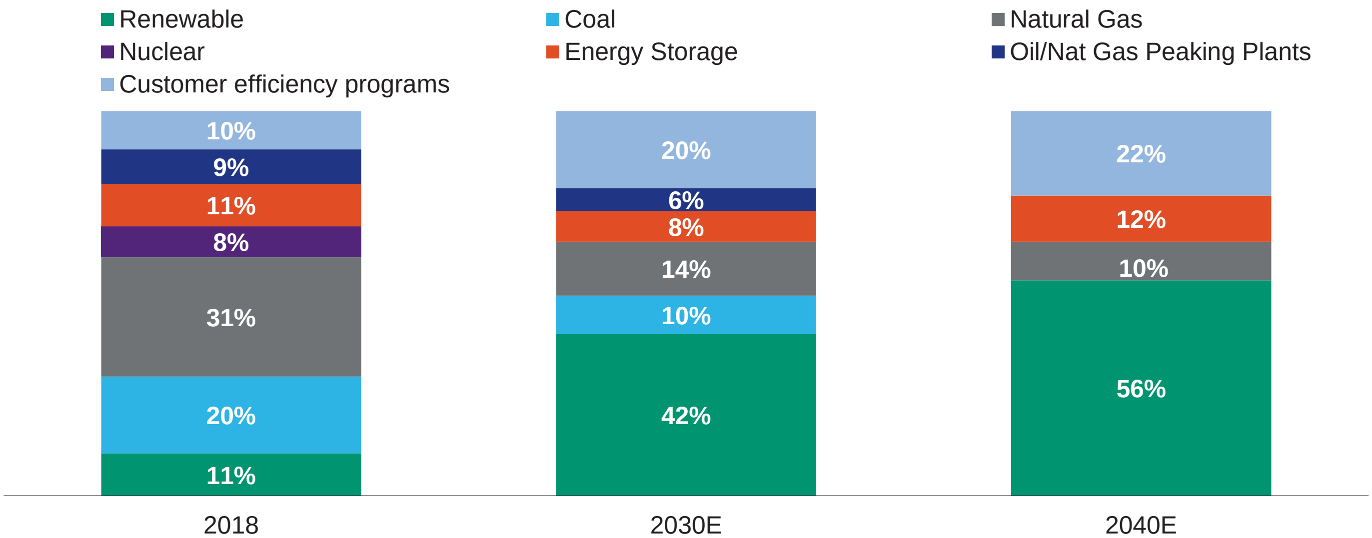
In 2018, about half of Consumers' electric generation was provided through long-term power purchase agreements or market purchases. The majority of this production came from two power purchase agreements, one with the 1,240 MW MCV gas-fired facility (approximately 16% of 2018 electric supply) that terminates in March 2025, and a second with the 791 MW Palisades nuclear facility (approximately 20% of 2018 electric supply) that is scheduled to terminate in 2022. The Palisades PPA is not expected to be renewed when it expires, while the company is proposing extending the MCV PPA for another five years in its IRP, albeit at a lower price. We expect that the company will replace any ensuing energy and capacity shortfall with a mix of renewable generation and demand side management initiatives.

Michigan state statutes allow utilities to securitize restructuring-related regulatory assets and stranded costs and the MPSC has a history of approving securitization bonds. Most recently, in 2013, the MPSC authorized Consumers' issuance of securitization bonds to finance the recovery of the remaining book value of seven smaller coal-fired electric generating plants that were retired in April 2016 and three smaller natural gas-fired units that were retired in June 2015. Approximately $378 million of securitization bonds were issued through a Consumers securitization subsidiary in 2014. Principal and interest payments are made semi-annually through the maturity of the bonds in 2029. We would expect similar regulatory treatment would be possible for other future plant retirement.

Elevated carbon transition risk within the regulated utility sector

Consumers has elevated carbon transition risk within the US regulated utility sector because it is a vertically integrated utility that has a large fossil based generation capacity. Consumers is currently in a transition to phase out its coal-fired generation and target to reduce its CO2 emission by 80% by 2040 from its 2005 levels. Michigan's regulatory framework supports Consumers' transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Exhibit 6
Clean Energy Plan Electric Capacity by Fuel Source (MW)



Source: Company presentations

Our carbon transition report for utilities can be found at Regulated Utilities: Prudent regulation key to mitigating risk, capturing opportunities of decarbonization and Moody's cross-sector methodology for assessing ESG risks can be found at General Principles for Assessing Environmental, Social and Governance Risks.

Liquidity analysis

We expect Consumers' liquidity profile to be adequate over the next 12-18 months.

Consumers external liquidity sources include its recently amended and extended $850 million secured revolving credit facility expiring June 2023. The facility added a sustainability-linked pricing metric, which permits an interest rate reduction by meeting targets related to environmental sustainability, specifically renewable generation, and highlights its commitment to shifting its exposure to a greater renewable content. Consumers also maintains a $250 million secured credit facility terminating in November 2020. These credit facilities provide support for working capital needs and act as a backstop to Consumers' $500 million commercial paper program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at less than 65%. At the period ending 31 March 2019, debt to capital was 47%.

As of 31 March 2019, Consumers had $30 million of commercial paper outstanding under its CP program, no borrowings under its various credit facilities and $52 million in aggregate of letters of credit outstanding. In addition to approximately $25 million of annual amortization of its securitization bonds, Consumers nearest long-term debt maturity are a first mortgage bonds totaling $100 million that are due in 2020. $350 million of first mortgage bond was redeemed in May 2019.

The utility's continuing capital expenditure program and dividend policy result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent.

For the last twelve months ended 31 March 2019, Consumers generated approximately $1.35 billion of cash from operations (CFO), invested $1.88 billion in capital investments and up streamed $586 million in dividend payments to CMS, resulting in a negative free cash flow (FCF) of approximately $1.12 billion that was offset by parent contributions of $500 million and incremental long-term debt. In 2018, Consumers generated CFO of approximately $1.45 billion, invested $1.82 billion in capital investments and up streamed about $533 million in dividend payments, resulting in negative FCF of $906 million offset by parent contributions of $250 million. CMS relies on Consumers' dividends to pay its interest expense, which amounted to around $135 million for full year 2018. Consumers policy is to grow its dividend with earnings, maintaining a payout ratio in the 80% range. After consideration of parent contributions, for last twelve months ending 31 March 2019, Consumers' net dividends to its parent equate to about 12% of its net income.

Structural considerations

Consumers strong stand-alone financial performance has been pressured by a significant debt level at CMS, the parent company. However, CMS has made slow but steady progress in reducing its consolidated leverage as well as the percentage of parent debt in its capital structure. At the end of the period ending 31 March 2019, CMS had approximately $5.3 billion of consolidated debt outside of Consumers, or approximately 44% of its consolidated total reported debt. Of this amount, approximately $1.8 billion represented deposits of EnerBank, an FDIC-insured industrial bank wholly owned by CMS, and is supported by approximately $1.9 billion of notes receivable. Excluding self-funding EnerBank, we estimate that CMS's parent level debt to be approximately $3.4 billion or about 34% of the total of Consumers plus pure parent level debt. This still remains as a key driver of the two notch rating differential between Consumers and CMS.

Rating methodology and scorecard factors

Exhibit 7
Rating Factors
Consumers Energy Company

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2019		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	7.0x	Aa	6x - 6.5x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	26.3%	A	20% - 24%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	18.6%	A	13% - 16%	Baa
d) Debt / Capitalization (3 Year Avg)	43.4%	A	43% - 47%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A1		A2
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard Indicated Outcome		A1		A2
b) Actual Rating Assigned		(P)A2		(P)A2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 03/31/2019 (LTM)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 8

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-15	Dec-16	Dec-17	Dec-18	LTM Mar-19
As Adjusted					
FFO	**1,633**	**1,739**	**1,825**	**1,760**	**1,800**
+/- Other	121	(49)	33	(101)	(134)
CFO Pre-WC	**1,754**	**1,690**	**1,858**	**1,659**	**1,666**
+/- ΔWC	226	64	(65)	1	(77)
CFO	**1,980**	**1,754**	**1,793**	**1,660**	**1,589**
- Div	476	500	523	532	585
- Capex	1,558	1,673	1,649	1,834	1,928
FCF	**(54)**	**(419)**	**(379)**	**(706)**	**(924)**
(CFO Pre-W/C) / Debt	27.4%	24.6%	26.9%	22.1%	23.2%
(CFO Pre-W/C - Dividends) / Debt	20.0%	17.4%	19.3%	15.0%	15.1%
FFO / Debt	25.5%	25.4%	26.4%	23.5%	25.1%
RCF / Debt	18.1%	18.1%	18.9%	16.4%	16.9%
Revenue	6,165	6,064	6,222	6,464	6,552
Cost of Good Sold	2,836	2,636	2,696	2,886	2,888
Interest Expense	274	288	298	315	311
Net Income	544	615	634	527	506
Total Assets	18,735	20,026	21,179	22,096	22,052
Total Liabilities	13,217	14,139	14,746	15,251	14,804
Total Equity	5,518	5,888	6,434	6,845	7,249

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 9

Peer Comparison Table [1]

	Consumers Energy Company (P)A2 Stable			DTE Electric Company (P)A2 Stable			DTE Gas Company A2 Negative			Northern States Power Company (Minnesota) (P)A2 Stable			Wisconsin Power and Light Company A2 Negative		
(in US millions)	FYE Dec-17	FYE Dec-18	LTM Mar-19	FYE Dec-17	FYE Dec-18	LTM Mar-19	FYE Dec-17	FYE Dec-18	LTM Mar-19	FYE Dec-17	FYE Dec-18	LTM Mar-19	FYE Dec-17	FYE Dec-18	LTM Mar-19
Revenue	6,222	6,464	6,552	5,102	5,298	5,328	1,368	1,415	1,510	5,102	5,122	5,162	1,473	1,453	1,486
CFO Pre-W/C	1,858	1,659	1,666	1,804	1,833	1,785	310	337	333	1,461	1,357	1,383	442	427	442
Total Debt	6,909	7,505	7,183	7,348	7,641	8,073	1,784	1,826	1,786	5,467	5,414	5,271	2,097	2,175	2,216
CFO Pre-W/C / Debt	26.9%	22.1%	23.2%	24.6%	24.0%	22.1%	17.4%	18.5%	18.7%	26.7%	25.1%	26.2%	21.1%	19.6%	19.9%
CFO Pre-W/C – Dividends / Debt	19.3%	15.0%	15.1%	18.7%	18.0%	16.3%	11.5%	12.3%	12.2%	17.5%	16.6%	17.9%	15.1%	13.2%	13.6%
Debt / Capitalization	46.1%	46.4%	44.1%	46.9%	46.0%	47.2%	46.4%	43.9%	42.7%	44.0%	43.0%	41.6%	46.8%	44.6%	44.6%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics

Ratings

Exhibit 10

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	Aa3
First Mortgage Bonds	Aa3
Senior Secured	Aa3
Senior Unsecured Shelf	(P)A2
Pref. Stock	A3
Commercial Paper	P-1
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Jr Subordinate	Baa2

Source: Moody's Investors Service

REPORT NUMBER 1179553

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Consumers Energy Company

(Subsidiary of CMS Energy Corporation)

Consumers Energy Company's 'A–' Long-Term Issuer Default Rating (IDR) primarily reflects the utility's low-risk regulated electric and natural gas operations and solid financial profile.

Key Rating Drivers

Constructive Regulatory Environment: Consumers Energy operates within a constructive regulatory environment overseen by the Michigan Public Service Commission (MPSC). Supportive state legislation and MPSC policies mitigate regulatory lag through the use of a forward test year, a 10-month review period for general rate cases (GRCs) and power supply and gas cost recovery mechanisms.

Consumers Energy's natural gas utility business also benefits from partial revenue decoupling, which annually reconciles Consumers Energy's actual weather-normalized, nonfuel revenues with the revenues approved by the MPSC.

2020 Electric GRC: In July 2020, Consumers Energy revised its electric rate filing with the MPSC, asking for a $229.7 million annual rate increase based on a 10.5% authorized ROE. The filing seeks approval to recover $13 million associated with Consumers Energy's deferral of depreciation and property tax expense and the overall rate of return on distribution-related capex exceeding certain amounts.

The filing also seeks approval of a method for recovering amounts earned under the financial compensation mechanism approved by the MPSC in Consumers Energy's integrated resource plan (IRP). This mechanism allows Consumers Energy to earn a financial incentive on power purchase agreements approved by the MPSC after Jan. 1, 2019. In addition, Consumers Energy proposes a new distributed generation tariff to replace the current net metering tariff, pursuant to the 2016 Energy Law. The MPSC is expected to provide a ruling on this GRC before YE20.

2018 Electric GRC: Fitch considers the last electric GRC to be balanced, incorporating the offsetting credit to customers from the federal Tax Cuts and Jobs Act (TCJA) of 2017. The MPSC approved the settlement agreement in January 2019, authorizing an annual net decrease of $24 million based on a 10.0% authorized ROE. The decrease consisted of an $89 million rate increase, which was more than offset by the $113 million TCJA credit. The agreement also provides deferred accounting treatment for certain distribution-related capex.

2019 Natural Gas GRC: Fitch considers the outcome of Consumers Energy's 2019 natural gas GRC to be balanced, resulting in a $144 million increase in base rates effective Oct. 1, 2020. The settlement agreement includes a 9.9% authorized ROE and continued use of partial revenue decoupling for Consumers Energy's natural gas utility operations.

Large Capex Plan: Consumers Energy has a large capex plan totaling $12.2 billion over 2020–2024. Roughly 45% of this capex is for electric utility operations, including existing generation, 14% for new renewable generation and 41% for natural gas utility operations. Concerns regarding the large capex plan are mitigated by the MPSC's constructive ratemaking policies, including the use of a forward test year, which allows for timely recovery of capex.

Cost Reductions and NOLs: Management's focus on cost reductions supports Consumers Energy's solid financial profile, reducing the negative near-term financial impact from the utility's large capex plan. In addition, the cash flow benefit from parent CMS Energy Corporation's (BBB/Stable) net operating loss carryforwards (NOLs) enables the utility to invest more internal capital into

Ratings

Rating Type	Rating	Outlook	Last Rating Action
Long-Term IDR	A-	Stable	Affirmed Sept. 25, 2020
Short-Term IDR	F2		Affirmed Sept. 25, 2020
Senior Secured Debt	A+		Affirmed Sept. 25, 2020
Senior Unsecured Debt	A		Affirmed Sept. 25, 2020
Preferred Stock	BBB+		Affirmed Sept. 25, 2020
CP	F2		Affirmed Sept. 25, 2020

Click here for full list of ratings

Applicable Criteria

Corporate Hybrids Treatment and Notching Criteria (November 2020)

Parent and Subsidiary Linkage Rating Criteria (August 2020)

Corporate Rating Criteria (May 2020)

Corporates Notching and Recovery Ratings Criteria (October 2019)

Related Research

CMS Energy Corporation (December 2020)

Fitch Affirms CMS Energy & Consumers Energy's Ratings; Outlook Stable (September 2020)

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improving the reliability of its service while minimizing the need for external sources of capital. Fitch expects ongoing cost reductions to average 2% per year.

Solid Financial Profile: Consumers Energy has a solid financial profile. Fitch does not currently expect the coronavirus pandemic to have a material impact on Consumers Energy's credit quality. FFO leverage is expected to be higher in 2020 due to $518 million of one-time pension contributions but then return within the rating sensitivity threshold for the current ratings by 2021. Fitch forecasts FFO leverage to average around 3.8x and total debt with equity credit/operating EBITDA around 3.8x through 2023.

Parent/Subsidiary Linkage: Fitch uses a bottom-up approach in determining the ratings on CMS Energy and Consumers Energy. The linkage follows a weak parent/strong subsidiary approach. Fitch considers Consumers Energy to be stronger than CMS Energy due to the utility's low-risk regulated operations, Michigan's constructive regulatory environment and CMS Energy's large amount of parent-level debt.

There is moderate linkage between the Long-Term IDRs of CMS Energy and Consumers Energy, created by the absence of guarantees and cross defaults and the utility's good access to debt capital markets. However, the utility's lack of strong ring-fencing provisions and CMS Energy's reliance on Consumers Energy as its predominant generator of cash flow would suggest closer linkage. Fitch caps at two notches the difference between the Long-Term IDRs of CMS Energy and Consumers Energy.

Financial Summary

($ Mil., as of Dec. 31)	2016	2017	2018	2019
Gross Revenue	6,030	6,187	6,430	6,342
Operating EBITDA	2,003	2,089	1,952	2,047
Cash Flow from Operations	1,656	1,690	1,424	1,569
Capital Intensity (Capex/Revenue) %	27.5	26.4	28.3	32.9
Total Debt with Equity Credit	5,882	5,939	6,791	7,198
FFO Interest Coverage (x)	7.0	7.4	5.9	6.7
FFO Leverage (x)	3.2	2.9	4.0	3.9
Total Debt with Equity Credit/Operating EBITDA (x)	2.9	2.8	3.5	3.5

Source: Fitch Ratings, Fitch Solutions.

Rating Derivation Relative to Peers

The credit profile of Consumers Energy is well positioned compared with those of peers DTE Electric Company (A–/Stable) and DTE Gas Company (BBB+/Stable) and comparable to those of Northern States Power Company-Minnesota (NSP-Minnesota; A–/Stable) and Northern States Power Company-Wisconsin (NSP-Wisconsin; A–/Stable). Fitch considers the regulatory environment in Michigan, Minnesota and Wisconsin to be constructive. Financial metrics are similar for Consumers Energy and its peers. Fitch forecasts FFO leverage to average around 3.8x through 2023 at Consumers Energy, 3.5x–3.7x at NSP-Minnesota and 3.5x–3.8x at NSP-Wisconsin. DTE Energy Company's (BBB/Stable) greater appetite for nonregulated midstream operations restricts the Long-Term IDR of DTE Electric to two notches above that of DTE.

Rating Sensitivities

Factors that Could, Individually or Collectively, Lead to a Positive Rating Action/Upgrade

- FFO leverage expected to be less than 3.6x on a sustained basis;
- A positive rating action on Consumers Energy would also require an equally positive rating action on its parent, CMS Energy. Fitch's parent/subsidiary linkage results in a maximum two-notch difference between the Long-Term IDRs of CMS Energy and Consumers Energy.

Factors that Could, Individually or Collectively, Lead to a Negative Rating Action/Downgrade

- FFO leverage expected to exceed 4.5x on a sustained basis;
- A material deterioration of the Michigan regulatory environment that results in less timely cost recovery or significantly weaker financial metrics;
- A downgrade to CMS Energy's Long-Term IDR.

Liquidity and Debt Structure

Adequate Liquidity: Fitch considers liquidity for CMS Energy and Consumers Energy to be adequate.

CMS Energy has a $550 million unsecured revolving credit facility (RCF) that will mature on June 5, 2023. As of Sept. 30, 2020, CMS Energy had $5 million of LCs outstanding and no borrowings outstanding, leaving $545 million of availability under its RCF.

Consumers Energy primarily meets its short-term liquidity needs through the issuance of CP under its $500 million CP program, which is supported by its $850 million RCF. Consumers Energy's RCF will mature on June 5, 2023 and is secured by the utility's first mortgage bonds (FMBs). Although the amount of outstanding CP does not reduce the RCF's available capacity, Consumers Energy states it would not issue CP in an amount exceeding the available RCF capacity. Consumers Energy had no CP borrowings and $7 million of LCs outstanding as of Sept. 30, 2020, leaving $843 million of unused availability under its RCF.

Consumers Energy has a separate $250 million RCF that matures on Nov. 19, 2022. This RCF had no borrowings and $1 million of LCs outstanding as of Sept. 30, 2020, leaving $249 million of availability. Consumers Energy also has a fully used $30 million LC facility that will mature on April18, 2022. Both facilities are secured by the utility's FMBs.

CMS Energy's operations require modest cash on hand. The company had $519 million of unrestricted cash and cash equivalents as of Sept. 30, 2020, $199 million of which was at Consumers Energy.

Consumers Energy has a manageable long-term debt maturity schedule over the next five years. The utility has $325 million of 3.375% FMBs due Aug. 15, 2023; $250 million of 3.125% FMBs due Aug. 31, 2024 and $51.5 million of 3.19% FMBs due Dec. 15, 2024.

ESG Considerations

The highest level of ESG credit relevance, if present, is a score of '3'. This means ESG issues are credit-neutral or have only a minimal credit impact on the entities, either due to their nature or to the way in which they are being managed by the entities. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

Key Assumptions

Fitch's Key Assumptions Within Its Rating Case for the Issuer Include

- Periodic GRC filings to recover Consumers Energy's investment in rate base and associated costs;
- Cost reductions averaging 2% per year;
- Flat annual electric and natural gas sales growth;
- Total utility capex of $12.2 billion over 2020–2024;
- Normal weather.

Financial Data

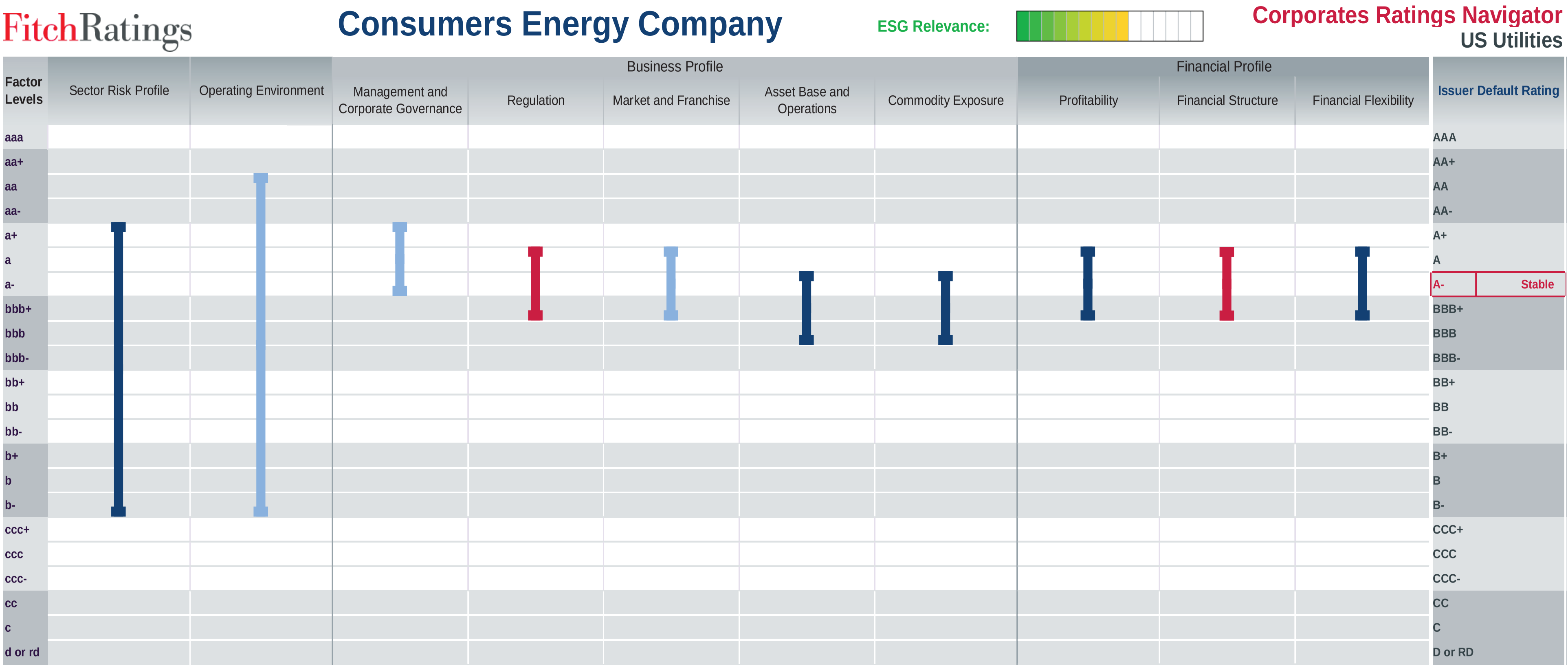
	Historical			
($ Mil., as of Dec. 31)	2016	2017	2018	2019
Summary Income Statement				
Gross Revenue	6,030	6,187	6,430	6,342
Revenue Growth (%)	(0.8)	2.6	3.9	(1.4)
Operating EBITDA (Before Income from Associates)	2,003	2,089	1,952	2,047
Operating EBITDA Margin (%)	33.2	33.8	30.4	32.3
Operating EBITDAR	2,017	2,104	1,963	2,080
Operating EBITDAR Margin (%)	33.4	34.0	30.5	32.8
Operating EBIT	1,225	1,243	1,056	1,104
Operating EBIT Margin (%)	20.3	20.1	16.4	17.4
Gross Interest Expense	(264)	(269)	(283)	(275)
Pretax Income (Including Associate Income/Loss)	936	971	847	928
Summary Balance Sheet				
Readily Available Cash and Equivalents	131	44	39	11
Total Debt with Equity Credit	5,882	5,939	6,791	7,198
Total Adjusted Debt with Equity Credit	5,994	6,059	6,879	7,462
Net Debt	5,751	5,895	6,752	7,187
Summary Cash Flow Statement				
Operating EBITDA	2,003	2,089	1,952	2,047
Cash Interest Paid	(264)	(269)	(284)	(257)
Cash Tax	(50)	1	(156)	(132)
Dividends Received Less Dividends Paid to Minorities (Inflow/(Out)flow)	0	0	0	0
Other Items Before FFO	(97)	(67)	(90)	(74)
FFO	1,592	1,755	1,423	1,584
FFO Margin (%)	26.4	28.4	22.1	25.0
Change in Working Capital	64	(65)	1	(15)
Cash Flow from Operations (Fitch Defined)	1,656	1,690	1,424	1,569
Total Non-Operating/Nonrecurring Cash Flow	0	0	0	0
Capex	(1,656)	(1,632)	(1,822)	(2,085)
Capital Intensity (Capex/Revenue) %	27.5	26.4	28.3	32.9
Common Dividends	(501)	(524)	(533)	(594)
FCF	(501)	(466)	(931)	(1,110)
Net Acquisitions and Divestitures	0	0	0	77
Other Investing and Financing Cash Flow Items	(87)	(98)	(140)	(115)
Net Debt Proceeds	394	27	816	445
Net Equity Proceeds	275	450	250	675
Total Change in Cash	81	(87)	(5)	(28)
Leverage Ratios (x)				
Total Net Debt With Equity Credit/Operating EBITDA	2.9	2.8	3.5	3.5
Total Adjusted Debt/Operating EBITDAR	3.0	2.9	3.5	3.6
Total Adjusted Net Debt/Operating EBITDAR	2.9	2.9	3.5	3.6
Total Debt with Equity Credit/Operating EBITDA	2.9	2.8	3.5	3.5

Financial Data

	Historical			
($ Mil., as of Dec. 31)	2016	2017	2018	2019
FFO-Adjusted Leverage	3.2	3.0	4.0	4.0
FFO-Adjusted Net Leverage	3.1	3.0	4.0	4.0
FFO Leverage	3.2	2.9	4.0	3.9
FFO Net Leverage	3.1	2.9	4.0	3.9
Calculations for Forecast Publication				
Capex, Dividends, Acquisitions and Other Items Before FCF	(2,157)	(2,156)	(2,355)	(2,602)
FCF After Acquisitions and Divestitures	(501)	(466)	(931)	(1,033)
FCF Margin (After Net Acquisitions) (%)	(8.3)	(7.5)	(14.5)	(16.3)
Coverage Ratios (x)				
FFO Interest Coverage	7.0	7.4	5.9	6.7
FFO Fixed-Charge Coverage	6.7	7.1	5.8	6.1
Operating EBITDA/Interest Paid + Rents	7.3	7.4	6.7	6.8
Operating EBITDA/Interest Paid	7.6	7.8	6.9	7.5
Additional Metrics (%)				
CFO-Capex/Total Debt with Equity Credit	0.0	1.0	(5.9)	(7.2)
CFO-Capex/Total Net Debt with Equity Credit	0.0	1.0	(5.9)	(7.2)

Source: Fitch Ratings, Fitch Solutions.

Ratings Navigator



Bar Chart Legend:			
Vertical Bars = Range of Rating Factor		Bar Arrows = Rating Factor Outlook	
Bar Colors = Relative Importance		⇧	Positive
■ (red)	Higher Importance	⇩	Negative
■ (dark blue)	Average Importance	⇳	Evolving
■ (light blue)	Lower Importance	□	Stable

Exhibit: AG-1.41

FitchRatings

Consumers Energy Company

Corporates Ratings Navigator
US Utilities

Operating Environment

aa+	Economic Environment	aa	Very strong combination of countries where economic value is created and where assets are located.
aa	Financial Access	aa	Very strong combination of issuer specific funding characteristics and of the strength of the relevant local financial market.
	Systemic Governance	aa	Systemic governance (eg rule of law, corruption; government effectiveness) of the issuer's country of incorporation consistent with 'aa'.
b-			
ccc+			

Regulation

a+	Degree of Transparency and Predictability	a	Track record of transparent and predictable regulation.
a	Timeliness of Cost Recovery	a	Minimal lag to recover capital and operating costs.
a-	Trend in Authorized ROEs	a	Above-average authorized ROE.
bbb+	Mechanisms Available to Stabilize Cash Flows	bbb	Revenues partially insulated from variability in consumption.
bbb	Mechanisms Supportive of Creditworthiness	bbb	Effective regulatory ring-fencing or minimum creditworthiness requirements.

Asset Base and Operations

a	Diversity of Assets	bbb	Good quality and/or reasonable scale diversified assets.
a-	Operations Reliability and Cost Competitiveness	a	Track record of reliable, low-cost operations.
bbb+	Exposure to Environmental Regulations	bbb	Limited or manageable exposure to environmental regulations.
bbb	Capital and Technological Intensity of Capex	bbb	Moderate reinvestments requirements in established technologies.
bbb-			

Profitability

a+	Free Cash Flow	bbb	Structurally neutral to negative FCF across the investment cycle.
a	Volatility of Profitability	a	Higher stability and predictability of profits relative to utility peers.
a-			
bbb+			
bbb			

Financial Flexibility

a+	Financial Discipline	a	Clear commitment to maintain a conservative policy with only modest deviations allowed.
a	Liquidity	bbb	One-year liquidity ratio above 1.25x. Well-spread maturity schedule of debt but funding may be less diversified.
a-	FFO Fixed Charge Cover	a	5.0x
bbb+			
bbb			

How to Read This Page: The left column shows the three-notch band assessment for the overall Factor, illustrated by a bar. The right column breaks down the Factor into Sub-Factors, with a description appropriate for each Sub-Factor and its corresponding category.

Management and Corporate Governance

aa-	Management Strategy	aa	Coherent strategy and very strong track record in implementation.
a+	Governance Structure	a	Experienced board exercising effective check and balances. Ownership can be concentrated among several shareholders.
a	Group Structure	a	Group structure shows some complexity but mitigated by transparent reporting.
a-	Financial Transparency	a	High quality and timely financial reporting.
bbb+			

Market and Franchise

a+	Market Structure	a	Well-established market structure with complete transparency in price-setting mechanisms.
a	Consumption Growth Trend	bbb	Customer and usage growth in line with industry averages.
a-	Customer Mix	a	Favorable customer mix.
bbb+	Geographic Location	bbb	Beneficial location or reasonable locational diversity.
bbb	Supply Demand Dynamics	bbb	Moderately favorable outlook for prices/rates.

Commodity Exposure

a	Ability to Pass Through Changes in Fuel	bbb	Limited exposure to changes in commodity costs.
a-	Underlying Supply Mix	bbb	Low variable costs and moderate flexibility of supply.
bbb+	Hedging Strategy	a	Highly captive supply and customer base.
bbb			
bbb-			

Financial Structure

a+	Lease Adjusted FFO Gross Leverage	a	3.5x
a	Total Adjusted Debt/Operating EBITDAR	a	3.25x
a-			
bbb+			
bbb			

Credit-Relevant ESG Derivation

Consumers Energy Company has 12 ESG potential rating drivers
- Emissions from operations
- Fuel use to generate energy and serve load
- Impact of waste from operations
- Plants' and networks' exposure to extreme weather
- Product affordability and access
- Quality and safety of products and services; data security

Showing top 6 issues

			Overall ESG
key driver	0	issues	5
driver	0	issues	4
potential driver	12	issues	3
not a rating driver	2	issues	2
	0	issues	1

For further details on Credit-Relevant ESG scoring, see page 3.

Exhibit: AG-1.41

FitchRatings

Consumers Energy Company

Corporates Ratings Navigator
US Utilities

Credit-Relevant ESG Derivation

Consumers Energy Company has 12 ESG potential rating drivers

- Consumers Energy Company has exposure to emissions regulatory risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to energy productivity risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to waste & impact management risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to extreme weather events but this has very low impact on the rating.
- Consumers Energy Company has exposure to access/affordability risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to customer accountability risk but this has very low impact on the rating.

Showing top 6 issues

			Overall ESG Scale
key driver	0	issues	5
driver	0	issues	4
potential driver	12	issues	3
not a rating driver	2	issues	2
	0	issues	1

Environmental (E)

General Issues	E Score	Sector-Specific Issues	Reference
GHG Emissions & Air Quality	3	Emissions from operations	Asset Base and Operations; Commodity Exposure; Regulation; Profitability
Energy Management	3	Fuel use to generate energy and serve load	Asset Base and Operations; Commodity Exposure; Profitability
Water & Wastewater Management	2	Water used by hydro plants or by other generation plants, also effluent management	Asset Base and Operations; Regulation; Profitability
Waste & Hazardous Materials Management; Ecological Impacts	3	Impact of waste from operations	Asset Base and Operations; Regulation; Profitability
Exposure to Environmental Impacts	3	Plants' and networks' exposure to extreme weather	Asset Base and Operations; Regulation; Profitability

E Scale: 5, 4, 3, 2, 1

Social (S)

General Issues	S Score	Sector-Specific Issues	Reference
Human Rights, Community Relations, Access & Affordability	3	Product affordability and access	Asset Base and Operations; Regulation; Profitability; Financial Structure
Customer Welfare - Fair Messaging, Privacy & Data Security	3	Quality and safety of products and services; data security	Regulation; Profitability
Labor Relations & Practices	3	Impact of labor negotiations and employee (dis)satisfaction	Asset Base and Operations; Profitability
Employee Wellbeing	2	Worker safety and accident prevention	Profitability; Asset Base and Operations
Exposure to Social Impacts	3	Social resistance to major projects that leads to delays and cost increases	Asset Base and Operations; Profitability

S Scale: 5, 4, 3, 2, 1

Governance (G)

General Issues	G Score	Sector-Specific Issues	Reference
Management Strategy	3	Strategy development and implementation	Management and Corporate Governance
Governance Structure	3	Board independence and effectiveness; ownership concentration	Management and Corporate Governance
Group Structure	3	Complexity, transparency and related-party transactions	Management and Corporate Governance
Financial Transparency	3	Quality and timing of financial disclosure	Management and Corporate Governance

G Scale: 5, 4, 3, 2, 1

How to Read This Page
ESG scores range from 1 to 5 based on a 15-level color gradation. Red (5) is most relevant and green (1) is least relevant.

The Environmental (E), Social (S) and Governance (G) tables break out the individual components of the scale. The left-hand box shows the aggregate E, S, or G score. General Issues are relevant across all markets with Sector-Specific Issues unique to a particular industry group. Scores are assigned to each sector-specific issue. These scores signify the credit-relevance of the sector-specific issues to the issuing entity's overall credit rating. The Reference box highlights the factor(s) within which the corresponding ESG issues are captured in Fitch's credit analysis.

The Credit-Relevant ESG Derivation table shows the overall ESG score. This score signifies the credit relevance of combined E, S and G issues to the entity's credit rating. The three columns to the left of the overall ESG score summarize the issuing entity's sub-component ESG scores. The box on the far left identifies the [number of] general ESG issues that are drivers or potential drivers of the issuing entity's credit rating (corresponding with scores of 3, 4 or 5) and provides a brief explanation for the score.

Classification of ESG issues has been developed from Fitch's sector and sub-sector ratings criteria and the General Issues and the Sector-Specific Issues have been informed with SASB's Materiality Map.

CREDIT-RELEVANT ESG SCALE

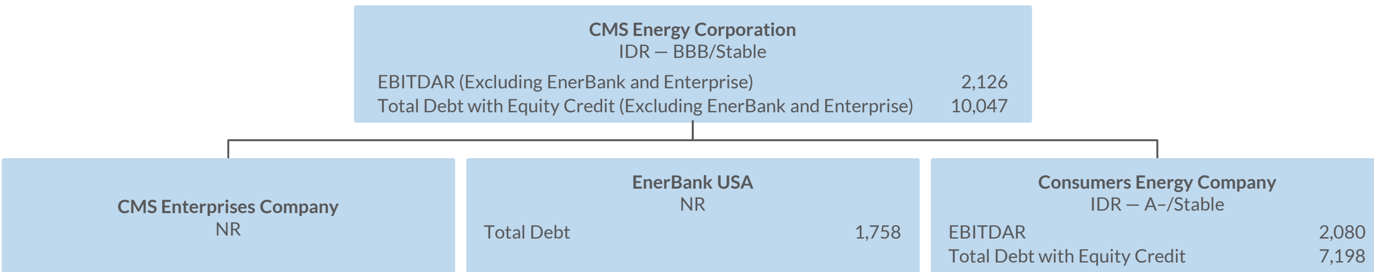
How relevant are E, S and G issues to the overall credit rating?

Score	Description
5	Highly relevant, a key rating driver that has a significant impact on the rating on an individual basis. Equivalent to "higher" relative importance within Navigator.
4	Relevant to rating, not a key rating driver but has an impact on the rating in combination with other factors. Equivalent to "moderate" relative importance within Navigator.
3	Minimally relevant to rating, either very low impact or actively managed in a way that results in no impact on the entity rating. Equivalent to "lower" relative importance within Navigator.
2	Irrelevant to the entity rating but relevant to the sector.
1	Irrelevant to the entity rating and irrelevant to the sector.

Exhibit: AG-1.41

Simplified Group Structure Diagram

Organizational Structure — CMS Energy Corporation
($ Mil., as of Dec. 31, 2019)



IDR – Issuer Default Rating. NR – Not rated.
Source: Fitch Ratings, Fitch Solutions, CMS Energy Corporation.

Peer Financial Summary

Company	Issuer Default Rating	Financial Statement Date	Gross Revenue ($ Mil.)	FFO ($ Mil.)	FFO Interest Coverage (x)	FFO Leverage (x)	Total Debt with Equity Credit/Operating EBITDA (x)
Consumers Energy Company	A–						
	A–	2019	6,342	1,584	6.7	3.9	3.5
	A–	2018	6,430	1,423	5.9	4.0	3.5
	A–	2017	6,187	1,755	7.4	2.9	2.8
DTE Gas Company	BBB+						
	BBB+	2019	1,462	385	5.8	4.2	4.2
	BBB+	2018	1,415	303	5.1	4.7	4.2
	BBB+	2017	1,368	317	5.8	4.5	3.9
DTE Electric Company	A–						
	A–	2019	5,224	1,532	6.0	4.2	3.6
	A–	2018	5,298	1,740	7.0	3.4	3.4
	A–	2017	5,102	1,588	7.1	3.5	3.3
Northern States Power Company-Minnesota	A–						
	A–	2019	5,112	1,330	7.0	3.6	3.3
	A–	2018	5,122	1,316	7.0	3.4	3.2
	A–	2017	5,102	1,400	7.1	3.1	3.0
Northern States Power Company-Wisconsin	A–						
	A–	2019	981	220	6.9	3.4	3.3
	A–	2018	1,022	232	7.3	3.2	3.0
	A–	2017	1,005	219	7.2	3.1	3.0
Public Service Company of Colorado	A–						
	A–	2019	4,237	1,289	7.4	3.7	3.8
	A–	2018	4,086	1,035	5.9	4.3	3.9
	A–	2017	4,043	1,142	7.0	3.5	3.4
Wisconsin Electric Power Company	A						
	A	2019	3,497	779	2.6	2.3	2.6
	A	2018	3,625	965	9.2	2.7	3.8
	A	2017	3,712	682	6.8	4.2	3.5

Source: Fitch Ratings, Fitch Solutions.

FitchRatings

Fitch Adjusted Financials

($ Mil., as of 12/31/19)	Notes and Formulas	Reported Values	Sum of Adjustments	Hybrid Adjustment	Fair Value and Other Debt Adjustments	CORP - Lease Treatment	Other Adjustments	Adjusted Values
Income Statement Summary								
Revenue		6,376	(34)				(34)	6,342
Operating EBITDAR		2,105	(25)			9	(34)	2,080
Operating EBITDAR After Associates and Minorities	(a)	2,105	(25)			9	(34)	2,080
Operating Lease Expense	(b)	0	33			33		33
Operating EBITDA	(c)	2,105	(58)			(24)	(34)	2,047
Operating EBITDA After Associates and Minorities	(d) = (a-b)	2,105	(58)			(24)	(34)	2,047
Operating EBIT	(e)	1,130	(26)			(18)	(8)	1,104
Debt and Cash Summary								
Total Debt with Equity Credit	(f)	7,544	(346)	19	(72)	(76)	(217)	7,198
Lease-Equivalent Debt	(g)	0	264			264		264
Other Off-Balance-Sheet Debt	(h)	0						0
Total Adjusted Debt with Equity Credit	(i) = (f+g+h)	7,544	(82)	19	(72)	188	(217)	7,462
Readily Available Cash and Equivalents	(j)	11						11
Not Readily Available Cash and Equivalents		17						17
Cash Flow Summary								
Operating EBITDA After Associates and Minorities	(d) = (a-b)	2,105	(58)			(24)	(34)	2,047
Preferred Dividends (Paid)	(k)	(2)						(2)
Interest Received	(l)	10						10
Interest (Paid)	(m)	(279)	4			18	(14)	(275)
Cash Tax (Paid)		(132)						(132)
Other Items Before FFO		(88)	22				22	(66)
Funds from Operations (FFO)	(n)	1,616	(32)			(6)	(26)	1,584
Change in Working Capital (Fitch-Defined)		(15)						(15)
Cash Flow from Operations (CFO)	(o)	1,601	(32)			(6)	(26)	1,569
Non-Operating/Nonrecurring Cash Flow		0						0
Capital (Expenditures)	(p)	(2,085)						(2,085)
Common Dividends (Paid)		(594)						(594)
Free Cash Flow (FCF)		(1,078)	(32)			(6)	(26)	(1,110)
Gross Leverage (x)								
Total Adjusted Debt/Operating EBITDAR[a]	(i/a)	3.6						3.6
FFO Adjusted Leverage	(i/(n-m-l-k+b))	4.0						4.0
FFO Leverage	(i-g)/ (n-m-l-k)	4.0						3.9
Total Debt with Equity Credit/ Operating EBITDA[a]	(i-g)/d	3.6						3.5
(CFO-Capex)/Total Debt with Equity Credit (%)	(o+p)/(i-g)	(6.4)						(7.2)
Net Leverage (x)								
Total Adjusted Net Debt/Operating EBITDAR[a]	(i-j)/a	3.6						3.6
FFO Adjusted Net Leverage	(i-j)/ (n-m-l-k+b)	4.0						4.0
FFO Net Leverage	(i-g-j)/ (n-m-l-k)	4.0						3.9

Fitch Adjusted Financials

($ Mil., as of 12/31/19)	Notes and Formulas	Reported Values	Sum of Adjustments	Hybrid Adjustment	Fair Value and Other Debt Adjustments	CORP - Lease Treatment	Other Adjustments	Adjusted Values
Total Net Debt with Equity Credit/ Operating EBITDA[a]	(i-g-j)/d	3.6						3.5
(CFO-Capex)/Total Net Debt with Equity Credit (%)	(o+p)/(i-g-j)	(6.4)						(7.2)
Coverage (x)								
Operating EBITDA/ (Interest Paid + Lease Expense)[a]	a/(-m+b)	7.5						6.8
Operating EBITDA/Interest Paid[a]	d/(-m)	7.5						7.5
FFO Fixed-Charge Coverage	(n-l-m-k+b)/ (-m-k+b)	6.7						6.1
FFO Interest Coverage	(n-l-m-k)/ (-m-k)	6.7						6.7

[a]EBITDA/R after dividends to associates and minorities.
Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company.

The ratings above were solicited and assigned or maintained at the request of the rated entity/issuer or a related third party. Any exceptions follow below.

Consumers Energy Company

Subsidiary of CMS Energy Corporation

Rating Type	Rating	Outlook	Last Rating Action
Long-Term IDR	A–	Stable	Review — No Action Oct. 26, 2018
Short-Term IDR	F2		Review — No Action Oct. 26, 2018
Senior Secured Debt	A+		Review — No Action Oct. 26, 2018
Senior Unsecured Debt	A		Review — No Action Oct. 26, 2018
Preferred Stock	BBB+		Review — No Action Oct. 26, 2018
CP	F2		Review — No Action Oct. 26, 2018

Click here for full list of ratings

Financial Summary

(USD Mil.)	Dec 2015	Dec 2016	Dec 2017	Dec 2018
Gross Revenue	6,079	6,030	6,187	6,431
Operating EBITDAR	1,799	2,017	2,104	1,967
Cash Flow from Operations	1,719	1,656	1,689	1,424
Capital Intensity (Capex/Revenue) %	25.3	27.5	26.4	28.3
Total Adjusted Debt with Equity Credit	5,610	5,993	6,023	6,901
FFO Fixed-Charge Coverage (x)	6.2	6.7	7.1	5.7
FFO-Adjusted Leverage (x)	3.4	3.2	3.0	4.0
Total Adjusted Debt/Operating EBITDAR (x)	3.1	3.0	2.9	3.5

Source: Fitch Ratings, Fitch Solutions.

Consumers Energy Company's Long-Term Issuer Default Rating (IDR) primarily reflects the utility's low-risk regulated electric and natural gas operations and solid financial profile.

Key Rating Drivers

Constructive Regulatory Environment: Consumers Energy operates within a constructive regulatory environment overseen by the Michigan Public Service Commission (MPSC). Supportive state legislation and MPSC policies mitigate regulatory lag through the use of a forward test year, a 10-month review period for general rate cases (GRCs), and power supply and gas cost recovery mechanisms.

2018 Electric GRC: Fitch Ratings considers the outcome of the 2018 electric GRC to be balanced, incorporating the offsetting credit to customers from the federal Tax Cuts and Jobs Act (TCJA) of 2017. The MPSC approved the settlement agreement in January 2019 authorizing an annual rate net decrease of $24 million, based on a 10.0% authorized ROE. The rate decrease consisted of an $89 million rate increase, which was more than offset by the $113 million TCJA credit. The settlement agreement also provides for deferred accounting treatment for distribution-related capital investments exceeding certain amounts.

Solid Financial Profile: Consumers Energy has a solid financial profile, although tax reform is expected to moderate the utility's financial metrics over the next few years. Fitch expects adjusted debt/EBITDAR to average around 3.0x–3.5x and FFO-adjusted leverage to average around 3.5x–4.0x through 2020.

Large Capex Program: Consumers Energy has a large capex program totaling $11.2 billion over 2019–2023. Fitch expects Consumers Energy's financial profile to remain supportive of the utility's ratings, despite the large capex program.

The utility benefits from constructive regulation and cash savings from O&M expense reductions and parent CMS Energy Corporation's (BBB/Stable) net operating loss (NOL) carryforwards, which will be used to help fund growth capex.

O&M Reductions and NOLs: Management's focus on O&M expense reductions supports the utility's solid financial profile, reducing the negative near-term financial impact from the utility's large capex program. In addition, the cash flow benefit from CMS Energy's NOLs enables the utility to invest more internal capital in improving the reliability of its service while minimizing the need for external sources of capital. Fitch expects ongoing O&M expense reductions to average 2% per year.

Parent/Subsidiary Linkage: Fitch uses a bottom-up approach in determining the ratings on CMS Energy and Consumers Energy. The linkage follows a weak parent/strong subsidiary approach. Fitch considers Consumers Energy to be stronger than CMS Energy due to the utility's low-risk operations, Michigan's constructive regulatory environment and CMS Energy's substantial parent-level debt.

There is moderate linkage between the Long-Term IDRs of CMS Energy and Consumers Energy, resulting from the absence of guarantees and cross defaults and the utility's good access to debt capital markets. However, the utility's lack of strong ring-fencing provisions and CMS Energy's reliance on Consumers Energy as its predominant generator of cash flow would suggest closer linkage. Fitch caps at two notches the difference between the Long-Term IDRs of CMS Energy and Consumers Energy.

Rating Derivation Relative to Peers

Rating Derivation Versus Peers	
Peer Comparison	The credit profile of Consumers Energy is well positioned compared with that of peers DTE Electric Company (A–/Stable) and DTE Gas Company (BBB+/Stable) and comparable to that of Northern States Power Company-Minnesota (A–/Stable) and Northern States Power Company-Wisconsin (A–/Stable). Fitch considers the regulatory environment in Michigan, Minnesota and Wisconsin to be constructive. Financial metrics are slightly stronger for Consumers Energy than for its peers, but its ratings are constrained due to ownership by a weaker parent. Fitch restricts the Long-Term IDR of Consumers Energy to two notches above that of CMS Energy. DTE Energy Company's (DTE; BBB+/Stable) greater appetite for riskier nonregulated midstream operations currently restricts the Long-Term IDR of DTE Electric to one notch above that of DTE.
Parent/Subsidiary Linkage	Fitch uses a bottom-up approach in determining the ratings on CMS Energy and Consumers Energy. The linkage follows a weak parent/strong subsidiary approach. Fitch considers Consumers Energy to be stronger than CMS Energy due to the utility's low-risk operations, Michigan's constructive regulatory environment and CMS Energy's substantial parent-level debt. There is moderate linkage between the Long-Term IDRs of CMS Energy and Consumers Energy, resulting from the absence of guarantees and cross defaults and the utility's good access to debt capital markets. However, the utility's lack of strong ring-fencing provisions and CMS Energy's reliance on Consumers Energy as its predominant generator of cash flow would suggest closer linkage. Fitch caps at two notches the difference between the Long-Term IDRs of CMS Energy and Consumers Energy
Country Ceiling	No Country Ceiling constraint was in effect for these ratings.
Operating Environment	No operating environment influence was in effect for these ratings.
Other Factors	Not applicable.

Source: Fitch Ratings.

Navigator Peer Comparison

Issuer		Business profile						Financial profile		
Name	IDR/Outlook	Operating Environment	Management and Corporate Governance	Regulation	Market and Franchise	Asset Base and Operations	Commodity Exposure	Profitability	Financial Structure	Financial Flexibility
Consumers Energy Company	A-/Sta	aa	a	a-	a-	bbb+	bbb+	a-	a	a-
DTE Electric Co.	A-/Neg	aa	a	a-	bbb+	bbb	bbb+	bbb	a	bbb+
DTE Gas Company	BBB+/Sta	aa	a	a-	bbb+	bbb+	a-	bbb	bbb+	bbb+
Northern States Power Company-Minnesota	A-/Sta	aa	a-	a-	a-	bbb+	bbb+	bbb+	a-	a-
Northern States Power Company-Wisconsin	A-/Sta	aa	a-	a	a-	bbb+	bbb+	bbb+	a-	a-
Public Service Company of Colorado	A-/Sta	aa	a-	a-	a-	bbb+	bbb+	a-	a-	a-
Wisconsin Electric Power Co.	A/Sta	aa	a-	a-	bbb+	bbb+	bbb+	bbb	bbb+	a
Wisconsin Public Service Corporation	A/Sta	aa	a-	a-	bbb+	bbb+	bbb+	bbb	bbb+	a

Source: Fitch Ratings. Importance: Higher, Moderate, Lower

Rating Sensitivities

Future Developments That May, Individually or Collectively, Lead to a Positive Rating Action

- A positive rating action on Consumers Energy would require an equally positive rating action on its parent, CMS Energy. CMS Energy's more leveraged credit profile constrains the ratings of Consumers Energy, and Fitch has imposed a maximum two-notch difference between the Long-Term IDRs of CMS Energy and Consumers Energy;
- A positive rating action for Consumers Energy would also require Fitch to expect FFO-adjusted leverage to remain less than 3.5x on a sustained basis.

Future Developments That May, Individually or Collectively, Lead to a Negative Rating Action

- A material deterioration of the Michigan regulatory environment;
- Adjusted debt/EBITDAR and FFO-adjusted leverage expected to exceed 3.8x and 4.5x, respectively, on a sustained basis;
- A downgrade to CMS Energy's Long-Term IDR.

Liquidity and Debt Structure

Adequate Liquidity: Fitch considers Consumers Energy's liquidity to be adequate.

Consumers Energy primarily meets its short-term liquidity needs through the issuance of CP under its $500 million CP program, which is supported by its $850 million revolving credit facility (RCF). Consumers Energy's RCF matures June 5, 2023 and is secured by the utility's first mortgage bonds (FMBs). Although the amount of outstanding CP does not reduce the RCF's available capacity, Consumers Energy states it would not issue CP in an amount exceeding the available RCF capacity. Consumers Energy had $30 million of CP borrowings and $7 million of LCs outstanding as of March 31, 2019, leaving $813 million of unused availability under its RCF.

Consumers Energy has a separate $250 million RCF that matures Nov. 23, 2020. This RCF had no borrowings and $15 million of LCs outstanding at March 31, 2019, leaving $235 million of availability. Consumers Energy also has a fully used $30 million LC facility that matures Sept. 9, 2019. Both facilities are secured by the utility's FMBs.

The utility's operations require modest cash on hand. Consumers Energy had $37 million of unrestricted cash and cash equivalents at March 31, 2019.

Consumers Energy has a busy yet manageable long-term debt maturity schedule over the next five years. The utility has $300 million of 5.65% FMBs due April 15, 2020; $100 million of 3.77% FMBs due Oct. 15, 2020; $375 million of 2.85% FMBs due May 15, 2022; $250 million of 5.3% FMBs due Sept. 1, 2022; and $325 million of 3.375% FMBs due Aug. 15, 2023.

Liquidity and Long-Term Debt Maturities

Scheduled Long-Term Debt Maturities (Excluding Securitization Bonds) at Dec. 31, 2018	**(USD Mil.)**
2019	0
2020	400
2021	0
2022	625
2023	325
Thereafter	5,020
Total Long-Term Debt (Excluding Securitization Bonds)	**6,370**

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company.

Liquidity Summary at March 31, 2019	**(USD Mil.)**
Unrestricted Cash and Cash Equivalents	37
Committed Bank Facilities	1,100
LC Facility	30
Short-Term Borrowings	30
LCs Outstanding	52
Availability Under Bank Facilities	1,048
Total Liquidity	**1,085**

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company.

Key Assumptions

Fitch's Key Assumptions Within Our Rating Case for Consumers Energy Include

- Periodic GRC filings to recover Consumers Energy's investment in rate base and associated costs;
- O&M cost reductions averaging 2% per year;
- Average annual electric sales growth of 0.5% and flat natural gas sales volume;
- Total capex of $11.2 billion over 2019–2023;
- Normal weather.

Financial Data

(USD Mil.)	Historical			
	Dec 2015	Dec 2016	Dec 2017	Dec 2018
Summary Income Statement				
Gross Revenue	6,079	6,030	6,187	6,431
Revenue Growth (%)	-9.9	-0.8	2.6	3.9
Operating EBITDA (Before Income from Associates)	1,780	2,003	2,089	1,953
Operating EBITDA Margin (%)	29.3	33.2	33.8	30.4
Operating EBITDAR	1,799	2,017	2,104	1,967
Operating EBITDAR Margin (%)	29.6	33.4	34.0	30.6
Operating EBIT	1,111	1,225	1,243	1,057
Operating EBIT Margin (%)	18.3	20.3	20.1	16.4
Gross Interest Expense	-243	-264	-269	-284
Pretax Income (Including Associate Income/Loss)	896	936	971	847
Summary Balance Sheet				
Readily Available Cash and Equivalents	50	131	44	39
Total Debt with Equity Credit	5,458	5,881	5,903	6,789
Total Adjusted Debt with Equity Credit	5,610	5,993	6,023	6,901
Net Debt	5,408	5,750	5,859	6,750
Summary Cash Flow Statement				
Operating EBITDA	1,780	2,003	2,089	1,953
Cash Interest Paid	-243	-264	-269	-284
Cash Tax	0	-50	1	-156
Dividends Received Less Dividends Paid to Minorities (Inflow/(Out)flow)	0	0	0	0
Other Items Before FFO	-165	-97	-67	-90
Funds Flow from Operations	1,372	1,592	1,754	1,423
FFO Margin (%)	22.6	26.4	28.3	22.1
Change in Working Capital	347	64	-65	1
Cash Flow from Operations (Fitch Defined)	1,719	1,656	1,689	1,424
Total Non-Operating/Nonrecurring Cash Flow	0	0	0	0
Capex	-1,537	-1,656	-1,632	-1,822
Capital Intensity (Capex/Revenue) %	25.3	27.5	26.4	28.3
Common Dividends	-476	-501	-524	-533
FCF	-294	-501	-467	-931
Net Acquisitions and Divestitures	-154	0	0	0
Other Investing and Financing Cash Flow Items	-90	-87	-123	-140
Net Debt Proceeds	367	394	27	816
Net Equity Proceeds	150	275	450	250
Total Change in Cash	-21	81	-113	-5
Calculations for Forecast Publication				
Capex, Dividends, Acquisitions and Other Items Before FCF	-2,167	-2,157	-2,156	-2,355
FCF After Acquisitions and Divestitures	-448	-501	-467	-931
FCF Margin (After Net Acquisitions) (%)	-7.4	-8.3	-7.5	-14.5
Coverage Ratios				
FFO Interest Coverage (x)	6.6	7.0	7.4	5.9
FFO Fixed-Charge Coverage (x)	6.2	6.7	7.1	5.7
Operating EBITDAR/Interest Paid + Rents (x)	6.9	7.3	7.4	6.6
Operating EBITDA/Interest Paid (x)	7.3	7.6	7.8	6.9
Leverage Ratios				
Total Adjusted Debt/Operating EBITDAR (x)	3.1	3.0	2.9	3.5
Total Adjusted Net Debt/Operating EBITDAR (x)	3.1	2.9	2.8	3.5
Total Debt with Equity Credit/Operating EBITDA (x)	3.1	2.9	2.8	3.5
FFO-Adjusted Leverage (x)	3.4	3.2	3.0	4.0
FFO-Adjusted Net Leverage (x)	3.4	3.1	2.9	4.0

Source: Fitch Ratings, Fitch Solutions.

Exhibit: AG-1.41

Ratings Navigator

FitchRatings

Consumers Energy Company

ESG Relevance:

Corporates Ratings Navigator
US Utilities

FitchRatings

Consumers Energy Company

Corporates Ratings Navigator
US Utilities

Operating Environment

aa+	Economic Environment	aa	Very strong combination of countries where economic value is created and where assets are located.
aa	Financial Access	aa	Very strong combination of issuer specific funding characteristics and of the strength of the relevant local financial market.
	Systemic Governance	aa	Systemic governance (eg rule of law, corruption; government effectiveness) of the issuer's country of incorporation consistent with 'aa'.
b-			
ccc+			

Management and Corporate Governance

aa-	Management Strategy	aa	Coherent strategy and very strong track record in implementation.
a+	Governance Structure	a	Experienced board exercising effective check and balances. Ownership can be concentrated among several shareholders.
a	Group Structure	a	Group structure shows some complexity but mitigated by transparent reporting.
a-	Financial Transparency	a	High quality and timely financial reporting.
bbb+			

Regulation

a+	Degree of Transparency and Predictability	a	Track record of transparent and predictable regulation.
a	Timeliness of Cost Recovery	a	Minimal lag to recover capital and operating costs.
a-	Trend in Authorized ROEs	a	Above-average authorized ROE.
bbb+	Mechanisms Available to Stabilize Cash Flows	bbb	Revenues partially insulated from variability in consumption.
bbb	Mechanisms Supportive of Creditworthiness	bbb	Effective regulatory ring-fencing or minimum creditworthiness requirements.

Market and Franchise

a+	Market Structure	a	Well-established market structure with complete transparency in price-setting mechanisms.
a	Consumption Growth Trend	bbb	Customer and usage growth in line with industry averages.
a-	Customer Mix	a	Favorable customer mix.
bbb+	Geographic Location	bbb	Beneficial location or reasonable locational diversity.
bbb	Supply Demand Dynamics	bbb	Moderately favorable outlook for prices/rates.

Asset Base and Operations

a	Diversity of Assets	bbb	Good quality and/or reasonable scale diversified assets.
a-	Operations Reliability and Cost Competitiveness	a	Track record of reliable, low-cost operations.
bbb+	Exposure to Environmental Regulations	bbb	Limited or manageable exposure to environmental regulations.
bbb	Capital and Technological Intensity of Capex	bbb	Moderate reinvestments requirements in established technologies.
bbb-			

Commodity Exposure

a	Ability to Pass Through Changes in Fuel	bbb	Limited exposure to changes in commodity costs.
a-	Underlying Supply Mix	bbb	Low variable costs and moderate flexibility of supply.
bbb+	Hedging Strategy	a	Highly captive supply and customer base.
bbb			
bbb-			

Profitability

a+	Free Cash Flow	bbb	Structurally neutral to negative FCF across the investment cycle.
a	Volatility of Profitability	a	Higher stability and predictability of profits relative to utility peers.
a-			
bbb+			
bbb			

Financial Structure

aa-	Lease Adjusted FFO Gross Leverage	a	3.5x
a+	Total Adjusted Debt/Operating EBITDAR	a	3.25x
a			
a-			
bbb+			

Financial Flexibility

a+	Financial Discipline	a	Clear commitment to maintain a conservative policy with only modest deviations allowed.
a	Liquidity	bbb	One-year liquidity ratio above 1.25x. Well-spread maturity schedule of debt but funding may be less diversified.
a-	FFO Fixed Charge Cover	a	5.0x
bbb+			
bbb			

How to Read This Page: The left column shows the three-notch band assessment for the overall Factor, illustrated by a bar. The right column breaks down the Factor into Sub-Factors, with a description appropriate for each Sub-Factor and its corresponding category.

Credit-Relevant ESG Derivation

Consumers Energy Company has 12 ESG potential rating drivers

- Emissions from operations
- Fuel use to generate energy and serve load
- Impact of waste from operations
- Plants' and networks' exposure to extreme weather
- Product affordability and access
- Quality and safety of products and services; data security

Showing top 6 issues

			Overall ESG
key driver	0	issues	5
driver	0	issues	4
potential driver	12	issues	3
not a rating driver	2	issues	2
	0	issues	1

For further details on Credit-Relevant ESG scoring, see page 3.

Navigator Version: RN 2.2.0.0

Exhibit: AG-1.41

FitchRatings

Consumers Energy Company

Corporates Ratings Navigator
US Utilities

Credit-Relevant ESG Derivation

Consumers Energy Company has 12 ESG potential rating drivers

- Consumers Energy Company has exposure to emissions regulatory risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to energy productivity risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to waste & impact management risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to extreme weather events but this has very low impact on the rating.
- Consumers Energy Company has exposure to access/affordability risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to customer accountability risk but this has very low impact on the rating.

Showing top 6 issues

			Overall ESG Scale
key driver	0	issues	5
driver	0	issues	4
potential driver	12	issues	3
not a rating driver	2	issues	2
	0	issues	1

Environmental (E)

General Issues	E Score	Sector-Specific Issues	Reference	E Scale
GHG Emissions & Air Quality	3	Emissions from operations	Asset Base and Operations; Commodity Exposure; Regulation; Profitability	5
Energy Management	3	Fuel use to generate energy and serve load	Asset Base and Operations; Commodity Exposure; Profitability	4
Water & Wastewater Management	2	Water used by hydro plants or by other generation plants, also effluent management	Asset Base and Operations; Regulation; Profitability	3
Waste & Hazardous Materials Management; Ecological Impacts	3	Impact of waste from operations	Asset Base and Operations; Regulation; Profitability	2
Exposure to Environmental Impacts	3	Plants' and networks' exposure to extreme weather	Asset Base and Operations; Regulation; Profitability	1

Social (S)

General Issues	S Score	Sector-Specific Issues	Reference	S Scale
Human Rights, Community Relations, Access & Affordability	3	Product affordability and access	Asset Base and Operations; Regulation; Profitability; Financial Structure	5
Customer Welfare - Fair Messaging, Privacy & Data Security	3	Quality and safety of products and services; data security	Regulation; Profitability	4
Labor Relations & Practices	3	Impact of labor negotiations and employee (dis)satisfaction	Asset Base and Operations; Profitability	3
Employee Wellbeing	2	Worker safety and accident prevention	Profitability; Asset Base and Operations	2
Exposure to Social Impacts	3	Social resistance to major projects that leads to delays and cost increases	Asset Base and Operations; Profitability	1

Governance (G)

General Issues	G Score	Sector-Specific Issues	Reference	G Scale
Management Strategy	3	Strategy development and implementation	Management and Corporate Governance	5
Governance Structure	3	Board independence and effectiveness; ownership concentration	Management and Corporate Governance	4
Group Structure	3	Complexity, transparency and related-party transactions	Management and Corporate Governance	3
Financial Transparency	3	Quality and timing of financial disclosure	Management and Corporate Governance	2
				1

How to Read This Page
ESG scores range from 1 to 5 based on a 15-level color gradation. Red (5) is most relevant and green (1) is least relevant.

The Environmental (E), Social (S) and Governance (G) tables break out the individual components of the scale. The left-hand box shows the aggregate E, S, or G score. General Issues are relevant across all markets with Sector-Specific Issues unique to a particular industry group. Scores are assigned to each sector-specific issue. These scores signify the credit-relevance of the sector-specific issues to the issuing entity's overall credit rating. The Reference box highlights the factor(s) within which the corresponding ESG issues are captured in Fitch's credit analysis.

The Credit-Relevant ESG Derivation table shows the overall ESG score. This score signifies the credit relevance of combined E, S and G issues to the entity's credit rating. The three columns to the left of the overall ESG score summarize the issuing entity's sub-component ESG scores. The box on the far left identifies the [number of] general ESG issues that are drivers or potential drivers of the issuing entity's credit rating (corresponding with scores of 3, 4 or 5) and provides a brief explanation for the score.

Classification of ESG issues has been developed from Fitch's sector and sub-sector ratings criteria and the General Issues and the Sector-Specific Issues have been informed with SASB's Materiality Map.

CREDIT-RELEVANT ESG SCALE

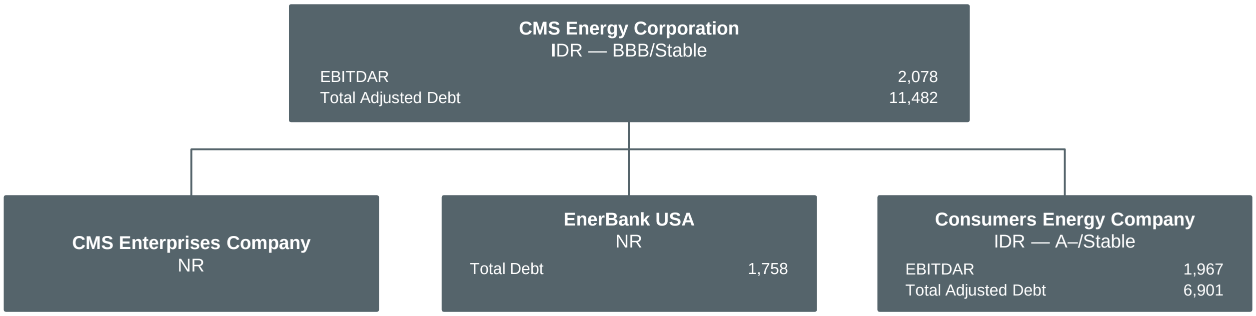
How relevant are E, S and G issues to the overall credit rating?

5	Highly relevant, a key rating driver that has a significant impact on the rating on an individual basis. Equivalent to "higher" relative importance within Navigator.
4	Relevant to rating, not a key rating driver but has an impact on the rating in combination with other factors. Equivalent to "moderate" relative importance within Navigator.
3	Minimally relevant to rating, either very low impact or actively managed in a way that results in no impact on the entity rating. Equivalent to "lower" relative importance within Navigator.
2	Irrelevant to the entity rating but relevant to the sector.
1	Irrelevant to the entity rating and irrelevant to the sector.

Exhibit: AG-1.41

Simplified Group Structure Diagram

Organizational Structure — CMS Energy Corporation
($ Mil., as of Dec. 31, 2018)



IDR – Long-Term Issuer Default Rating. NR – Not rated.
Source: Fitch Ratings, Fitch Solutions, CMS Energy Corporation.

Peer Financial Summary

Company	Issuer Default Rating	Financial Statement Date	Gross Revenue (USD Mil.)	Funds Flow from Operations (USD Mil.)	FFO Fixed-Charge Coverage (x)	FFO-Adjusted Leverage (x)	Total Adjusted Debt/Operating EBITDAR (x)
Consumers Energy Company	A–						
	A–	2018	6,431	1,423	5.7	4.0	3.5
	A–	2017	6,187	1,754	7.1	3.0	2.9
	A–	2016	6,030	1,592	6.7	3.2	3.0
DTE Electric Company	A–						
	A–	2018	5,298	1,740	6.6	3.4	3.4
	A–	2017	5,102	1,588	6.5	3.5	3.3
	A–	2016	5,225	1,720	6.9	3.1	3.1
DTE Gas Company	BBB+						
	BBB+	2018	1,415	303	5.1	4.7	4.2
	BBB+	2017	1,368	317	5.8	4.5	3.9
	BBB+	2016	1,308	377	7.2	3.3	3.6
Northern States Power Company-Minnesota	A–						
	A–	2018	5,122	1,316	6.6	3.4	3.3
	A–	2017	5,102	1,400	6.7	3.2	3.0
	A–	2016	4,900	1,318	6.4	3.3	3.4
Northern States Power Company-Wisconsin	A–						
	A–	2018	1,022	232	7.1	3.3	3.1
	A–	2017	1,005	219	7.0	3.1	3.0
	A–	2016	957	206	6.7	3.1	3.1
Public Service Company of Colorado	A–						
	A–	2018	4,086	1,035	5.6	4.3	4.0
	A–	2017	4,043	1,142	6.6	3.5	3.4
	A–	2016	4,048	1,092	6.5	3.5	3.3
Wisconsin Electric Power Co.	A						
	A	2018	3,625	965	9.0	3.1	4.4
	A	2017	3,712	682	6.6	4.3	3.5
	A	2016	3,793	755	7.0	3.8	3.5

Source: Fitch Ratings, Fitch Solutions.

Reconciliation of Key Financial Metrics

(USD Millions, As reported)	31 Dec 2018
Income Statement Summary	
Operating EBITDA	1,953
+ Recurring Dividends Paid to Non-controlling Interest	0
+ Recurring Dividends Received from Associates	0
+ Additional Analyst Adjustment for Recurring I/S Minorities and Associates	0
= Operating EBITDA After Associates and Minorities (k)	**1,953**
+ Operating Lease Expense Treated as Capitalised (h)	**14**
= Operating EBITDAR after Associates and Minorities (j)	**1,967**
Debt & Cash Summary	
Total Debt with Equity Credit (l)	**6,789**
+ Lease-Equivalent Debt	112
+ Other Off-Balance-Sheet Debt	0
= Total Adjusted Debt with Equity Credit (a)	**6,901**
Readily Available Cash [Fitch-Defined]	39
+ Readily Available Marketable Securities [Fitch-Defined]	0
= Readily Available Cash & Equivalents (o)	**39**
Total Adjusted Net Debt (b)	**6,862**
Cash-Flow Summary	
Preferred Dividends (Paid) (f)	**(2)**
Interest Received	10
+ Interest (Paid) (d)	**(284)**
= Net Finance Charge (e)	**(274)**
Funds From Operations [FFO] (c)	**1,423**
+ Change in Working Capital [Fitch-Defined]	1
= Cash Flow from Operations [CFO] (n)	**1,424**
Capital Expenditures (m)	**(1,822)**
Multiple applied to Capitalised Leases	**8.0**
Gross Leverage	
Total Adjusted Debt / Op. EBITDAR* [x] (a/j)	**3.5**
FFO Adjusted Gross Leverage [x] (a/(c-e+h-f))	**4.0**
Total Adjusted Debt/(FFO - Net Finance Charge + Capitalised Leases - Pref. Div. Paid)	
Total Debt With Equity Credit / Op. EBITDA* [x] (l/k)	**3.5**
Net Leverage	
Total Adjusted Net Debt / Op. EBITDAR* [x] (b/j)	**3.5**
FFO Adjusted Net Leverage [x] (b/(c-e+h-f))	**4.0**
Total Adjusted Net Debt/(FFO - Net Finance Charge + Capitalised Leases - Pref. Div. Paid)	
Total Net Debt / (CFO - Capex) [x] ((l-o)/(n+m))	**-17.0**
Coverage	
Op. EBITDAR / (Interest Paid + Lease Expense)* [x] (j/-d+h)	**6.6**
Op. EBITDA / Interest Paid* [x] (k/(-d))	**6.9**
FFO Fixed Charge Cover [x] ((c+e+h-f)/(-d+h-f))	**5.7**
(FFO + Net Finance Charge + Capit. Leases - Pref. Div Paid) / (Gross Int. Paid + Capit. Leases - Pref. Div. Paid)	
FFO Gross Interest Coverage [x] ((c+e-f)/(-d-f))	**5.9**
(FFO + Net Finance Charge - Pref. Div Paid) / (Gross Int. Paid - Pref. Div. Paid)	

*EBITDA/R after dividends to associates and minorities.

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company.

Fitch Adjustment Reconciliation

	Reported Values 31 Dec 18	Sum of Fitch Adjustments	Adjusted Values
Income Statement Summary			
Revenue	6,464	(33)	6,431
Operating EBITDAR	2,000	(33)	1,967
Operating EBITDAR after Associates and Minorities	2,000	(33)	1,967
Operating Lease Expense	14	0	14
Operating EBITDA	1,986	(33)	1,953
Operating EBITDA after Associates and Minorities	1,986	(33)	1,953
Operating EBIT	1,065	(8)	1,057
Debt & Cash Summary			
Total Debt With Equity Credit	7,009	(220)	6,789
Total Adjusted Debt With Equity Credit	7,121	(220)	6,901
Lease-Equivalent Debt	112	0	112
Other Off-Balance Sheet Debt	0	0	0
Readily Available Cash & Equivalents	39	0	39
Not Readily Available Cash & Equivalents	17	0	17
Cash-Flow Summary			
Preferred Dividends (Paid)	(2)	0	(2)
Interest Received	10	0	10
Interest (Paid)	(287)	3	(284)
Funds From Operations [FFO]	1,448	(25)	1,423
Change in Working Capital [Fitch-Defined]	1	0	1
Cash Flow from Operations [CFO]	1,449	(25)	1,424
Non-Operating/Non-Recurring Cash Flow	0	0	0
Capital (Expenditures)	(1,822)	0	(1,822)
Common Dividends (Paid)	(533)	0	(533)
Free Cash Flow [FCF]	(906)	(25)	(931)
Gross Leverage			
Total Adjusted Debt / Op. EBITDAR* [x]	3.6		3.5
FFO Adjusted Leverage [x]	4.1		4.0
Total Debt With Equity Credit / Op. EBITDA* [x]	3.5		3.5
Net Leverage			
Total Adjusted Net Debt / Op. EBITDAR* [x]	3.5		3.5
FFO Adjusted Net Leverage [x]	4.1		4.0
Total Net Debt / (CFO - Capex) [x]	-18.7		-17.0
Coverage			
Op. EBITDAR / (Interest Paid + Lease Expense)* [x]	6.6		6.6
Op. EBITDA / Interest Paid* [x]	6.9		6.9
FFO Fixed Charge Coverage [x]	5.7		5.7
FFO Interest Coverage [x]	6.0		5.9

*EBITDA/R after dividends to associates and minorities.
Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company.

Related Research & Criteria

Fitch Rates Consumers Energy Company's FMBs 'A+' (May 2019)
Short-Term Ratings Criteria (May 2019)
Corporate Rating Criteria (February 2019)
Corporate Hybrids Treatment and Notching Criteria (November 2018)
CMS Energy Corporation (September 2018)
Parent and Subsidiary Rating Linkage (July 2018)
Corporates Notching and Recovery Ratings Criteria (March 2018)
Fitch Affirms CMS & Sub; Rates CMS's Junior Sub Notes 'BB+' (March 2018)

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The ratings above were solicited and assigned or maintained at the request of the rated entity/issuer or a related third party. Any exceptions follow below.

MICHIGAN PUBLIC SERVICE COMMISSION **Exhibit AG-1.42**
Consumers Energy Company - Electric Rate Case **Case No. U-20963**
June 22, 2021
Page 1 of 1

Rating Agency Cash Flow Ratios
(With ROE at 9.5% and a 50% Common Equity Ratio)

Line	Caption		2020 Adjusted Moody's Cash Flow Ratio ($ Millions) Cash From Operations Pre-Wkg. Cap.	Debt	Ratio (e) / (f)	Note
	(a)		(b)	(c)	(d)	
1	**2020 Ratio Results**		$ 1,858	$ 8,540	**21.8%**	1
2	Reduce Common Equity (to 50% vs 50.6%)		(9)	91		2
3	Reduce ROE (to 9.5% vs 9.7%)		(17)			3
4	**Pro Forma w/50% Common Equity, 9.5% ROE**	0	$ 1,832	$ 8,631	**21.2%**	L 1 + L 2 + L 3
5	**Ratings Downgrade Risk**				***Below 18%***	4

Notes
1 From page 2 of Moody's May 10, 2021 report on Consumers Energy (see AG-CE-615)

2 As noted below under "Avg. 2020 Capitalization", the Company's Common Equity was 50.55% in 2020. Adjusting to 50% shifts $91 million from common equity to long-term debt (0.55% x $16.6 billion = $91 million).
Lower Common Equity of $91 million x the Company's authorized ROE of 9.9% = $9 million in lower Net Income.

3 Reducing the ROE from 9.7% (actual) to 9.5% produces a $17 million reduction in total Company earnings (0.2% x $8.4 billion = $17 million).
Note: Consumers 2020 Net Income of $ 814 million (p. 100, form 10-K) / $8.4 billion (below) = a 9.7% ROE

4 From page 2 of Moody's May 10, 2021 report on Consumers Energy (see AG-CE-615)

Average 2020 Capitalization ($ Millions)	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Average	%
Long Term Debt	$ 7,616	$ 7,867	$ 7,458	$ 7,742	$ 7,671	
Current Maturities	521	556	557	384	505	
Total	$ 8,137	$ 8,423	$ 8,015	$ 8,126	$ 8,175	49.23%
Preferred Stock	37	37	37	37	37	0.22%
Common Equity	8,066	8,468	8,526	8,519	8,395	50.55%
Consumers Energy Capital (per SEC Filings)	$ 16,240	$ 16,928	$ 16,578	$ 16,682	$ 16,607	**100.00%**

Question:

9. Refer to Exhibit A-32 (MRB-10). Please:

   a. Confirm that the balance sheet capitalization amounts are "at a moment in time" and are not an average of monthly or quarterly balances over a full year. If not confirming, please explain.

   b. Confirm that the Company has not verified that the capitalization amounts and ratios are the same amounts and ratios approved by the regulatory commission in setting rates for each of the listed companies. If not confirming, please explain the process that the Company employed to achieve the verification.

Response:

a. Confirmed.

b. I did not investigate the individual regulatory proceedings of each peer group company's regulated subsidiaries in order to determine if the calculated equity ratios were the same as those approved by the state regulators of those companies. However, the actual equity ratios of the regulated subsidiaries are publicly available and more directly accessible data that provides a good indication of the average equity ratios for the Company's peer group.

MARC R. BLECKMAN
May 14, 2021

U20963-AG-CE-615
Page **1** of **1**

Question:

2. Provide a copy of all rating agency reports covering CMS Energy and Consumers Energy for 2019, 2020, and 2021.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that CMS Energy is not a party to this case. Subject to the Company's objection, and without waiving that objection, Consumers Energy responds as follows:

Please find the requested ratings agency credit opinions for Consumers Energy in U20963-AG-CE-615-Bleckman_ATT_1.

MARC R. BLECKMAN
May 14, 2021

VLFAlert

ValueLine*funds*

4th Quarter 2018

Volume VII, Issue IV

00207257

Mitchell Appel
President
Value Line Funds

Dear Fellow Shareholder,

Thank you for choosing Value Line Funds as a part of your diversified investment portfolio. For over half a century, Value Line Funds has championed sound investment principles and helped thousands of investors accomplish their financial goals with our actively managed family of mutual funds.

We hope you enjoy this edition of the VLFAlert and thank you for your continued support.

Volatility is Not Risk:

Why the Difference is Critical to Long-Term Results

2017 lulled many equity investors into a comfort zone based on historically low volatility. 2018 has been more volatile—with tighter monetary policy and geopolitical and trade policy uncertainty among the drivers of the increase. But volatility levels in 2018 are actually historically normal—even with the bouts of volatility anticipated ahead of the November mid-term elections. But volatility is not risk. And recognizing the difference can be critical to your long-term investment returns.

Defining Our Terms

Volatility is simply the measure of the up and down movements of the market. For example, since 1950, when the Value Line Funds were first established, the average maximum drawdown in the broad U.S. equity market during midterm election years has been -17%, with weakness tending to be concentrated in the pre-election days. However, the good news is that there has been a consistent tendency historically for post-drawdown rallies, averaging +32% in the subsequent year.[1] Volatility? Yes! Uncertainty? Yes! But volatility is only risk if you act during down times—that is, only if you sell. To which the often-invoked quip may well be the most prudent answer: "Don't just do something, sit there."

Risk, on the other hand, is the probability of a permanent loss. You might think of risk as the possibility of having to lower your quality of life in the future.

> **"Volatility is not synonymous of risk but—for those who truly understand it—of wealth."**
>
> *- Francois Rochon**

Recognizing the Difference

Volatility is independent of risk. Too many investors let an investment's short-term price movements, or perceptions of short-term price movements, drive their buying and selling decisions. Too often volatility is regarded as something to be avoided. But since short-term price moves are unknowable and independent of underlying fundamentals and value, such volatility should not be a determinant.

And ALL investments have risk of some kind, including cash and CDs. One just needs to pick the risks that are best to take based on your individual tolerance level, time horizon and financial needs and goals.

As famed investor and Berkshire Hathaway CEO Warren Buffet wrote:

> "Stock prices will always be far more *volatile* than cash-equivalent holdings. *Over the long term*, however, currency-denominated instruments are *riskier* investments — far riskier investments — than widely-diversified stock portfolios that are bought over time and that are owned in a manner invoking only token fees and commissions. **That lesson has not customarily been taught in business schools, where volatility is almost universally used as a proxy for risk. Though this pedagogic assumption makes for easy teaching, it is dead wrong: Volatility is *far* from synonymous with risk.** Popular formulas that equate the two terms lead students, investors and CEOs astray."[2]

> **"Volatility is our friend. Volatility has nothing to do with risk."**
>
> *- Mohnish Pabrai**

(continued on back)

It's a Matter of Time, Not Timing

Most experienced investors do not fear volatility, only unrecoverable loss. But most losses, as measured by a day, a week, a quarter or a year, are recoverable over time. Declines in principal value have historically been temporary. Of course, there are true risks. A company could go totally out of business. An innovation could transform an industry so profoundly to make a once "blue chip" company a relic. A geopolitical event could happen to negate all assumptions. But these occurrences are rare. For the vast majority of investors, maintaining a long-term perspective is the real key to attaining gains over their investing lifetime. Historically, since World War II, the longer you hold stocks, the narrower the range of returns.[3] In other words, even if volatility is a concern, it decreases the longer you hold stocks. It's the old adage: what matters is time in the market, not market timing.

"You can't overlook the volatility, but you don't let it push you around in the market."

*- Boone Pickens**

solutions designed to meet a broad array of investment goals. Whether you are looking for income or long-term capital appreciation, whether you choose to invest in equities, taxabl or tax-exempt fixed income or a hybrid fund of multiple asset classes, you can rely on the solid fundamentals of Value Line Funds.

Value Line Funds Include:
Equity Funds
Premier Growth Fund
Larger Companies Focused Fund
Mid Cap Focused Fund
Small Cap Opportunities Fund
Hybrid Funds
Asset Allocation Fund
Capital Appreciation Fund
Fixed Income Funds
Tax Exempt Fund
Core Bond Fund

Operations & Maintenance - Summary

Line	Description (a)		Thousands Of Dollars (b)	Note or Ref. (c)
1	**O&M Expense Per Company**		**$ 696,264**	1
2	**Attorney General Changes**			
3	**Inflationary Cost Adjustments**		(7,777)	Testimony
4	**Electric Distribution:**		(34,503)	
5	Non-Forestry Reliability	$ (3,787)		Testimony
6	Operations, Maintance and Metering	(7,511)		Testimony
7	Service Restoration	(13,761)		Testimony
8	Field Operations	(6,118)		Testimony
9	Engineering Planning	(3,326)		Testimony
10	**Line Clearing**		(19,521)	Testimony
11	**Power Generation**		(11,012)	Testimony
12	**Customer Experience & Operations**		(7,851)	
13	Analytics and Outreach	(1,404)		Testimony
14	CRM System	(1,441)		Testimony
15	C&I Account Management system	(1,206)		Testimony
16	Bill Redesign and Delivery Transformation	(1,600)		Testimony
17	Customer Loyalty and Alternative Payment Methods	(2,200)		Testimony
18	**Uncollectible Accounts Expense**		(2,888)	Ex. AG-1.54
19	**Corporate Expenses**		(6,798)	
20	Employee Development projects	(1,550)		Testimony
21	IT Projects O&M Expense	(665)		Testimony
22	Insurance Expense	(4,583)		Ex. AG-1.46
23	**Information Technology**		(6,102)	
24	IT Investment Expense	(4,567)		Testimony
25	Digital-Hybrid Cloud Data Center Migration	(1,535)		Testimony
26	**Incentive Compensation**		(5,852)	Testimony
27	**Employee Benefits**		(6,535)	Testimony
28	(Sum of L. 3 to L. 27)		**(101,062)**	
29				
30	**AG Revised O&M amount**		**$ 595,202**	
31				
32	**Change in O&M** **(L. 30 less L. 1)**		**$ (101,062)**	

Note 1 Per Company Exhibit A-13 (JRC-41), Sched. C-5, page 1, Line 21

U20963-SA-CE-260
Requested By: Shannon M. Rueckert (SMR-1)
Respondent: Jason R. Coker
Date of Response: April 28, 2021
Page **1** of **1**

Question:

1. Please replace the Company's annual inflation rates and annual merit increases in all exhibits listed on the Company's Inflation Index that contain components of inflation with single inflation factors of 1.24% in 2020, 2.47% in 2021, and 1.93% in 2022.

a. Please provide the exhibits with replaced inflation factors in response

b. Please provide the Inflation Index with an additional column showing the difference between projections using Staff's single inflation rates and the Company's rates.

Response:

a. Please see U20963-SA-CE-Coker_ATT_1.
b. Please see U20963-SA-CE-Coker_ATT_1.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CECo Response to SA-CE-260

U20963-SA-CE-260-Coker_ATT_1

Schedule: C-5a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Inflation and Merit Increases Included in Projected Other Operation and Maintenance Expenses **Using Staff's Rates**
For the Projected 12-Month Period Ending December 31, 2022
($000)

Case No.: U-20963
Exhibit No.: A-13 (JRC-42)
Schedule: C-5a
Witness: JRCoker

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
				Projected Adjustments Using Staff's Rates							
Line No.	Description	Source	Historical 12 Months Ended 12/31/2019	Inflation for the 12 Months Ended 12/30/2020	Inflation for the 12 Months Ended 12/31/2021	Inflation for the 12 Months Ended 12/31/2022	Other Adjustments	Total Projected Adjustments	Projected 12 Months Ended 12/31/2022	As Filed 12 Months Ended 12/31/2022	Difference
								∑ (d) thru (g)	(c) + (h)		(j) - (i)
1	Electric Division - Electric & Common	U20963-SA-CE-260-Coker_ATT_1, p.2	174,012	761	2,915	2,334	2,770	8,779	182,791	185,039	2,248
2	Forestry	U20963-SA-CE-260-Coker_ATT_1, p.3	53,290	661	1,352	1,622	37,001	40,636	93,926	94,355	429
3	Generation	U20963-SA-CE-260-Coker_ATT_1, p.4	133,015	1,649	3,354	2,666	13,964	21,633	154,648	156,662	2,014
4	Operations Support	U20963-SA-CE-260-Coker_ATT_1, p.5	16,321	41	86	71	(103)	96	16,417	16,554	138
5	Information Technology Operations	U20963-SA-CE-260-Coker_ATT_1, p.6	43,830	132	267	213	2,355	2,967	46,797	47,242	444
6	Information Technology Investments	U20963-SA-CE-260-Coker_ATT_1, p.7	10,836	-	-	-	9,660	9,660	20,496	20,496	-
7	Customer Interactions	U20963-SA-CE-260-Coker_ATT_1, p.8	26,509	219	441	353	3,112	4,125	30,634	31,371	736
8	Billing & Payment	U20963-SA-CE-260-Coker_ATT_1, p.8	19,474	39	78	63	4,658	4,838	24,312	24,441	130
9	Demand Response	U20963-SA-CE-260-Coker_ATT_1, p.8	12,776	26	53	42	26,371	26,492	39,267	39,356	88
10	Pension Plans A/B	Exhibit No.: A-62 (LBC-1)	5,546	-	-	-	(14,448)	(14,448)	(8,902)	(8,902)	-
11	Defined Company Contribution Plan	Exhibit No.: A-62 (LBC-1)	8,567	-	-	-	3,561	3,561	12,128	12,128	-
12	401(k) Employees' Savings Plan	Exhibit No.: A-62 (LBC-1)	8,273	-	-	-	3,300	3,300	11,573	11,573	-
13	Active Health Care/Life Insurance/LTD	Exhibit No.: A-62 (LBC-1)	25,353	-	-	-	(1,497)	(1,497)	23,856	23,856	-
14	Retiree Health Care and Life Insurance	Exhibit No.: A-62 (LBC-1)	(40,032)	-	-	-	(23,269)	(23,269)	(63,301)	(63,301)	-
15	Other Benefits	Exhibit No.: A-62 (LBC-1)	1,695	-	-	-	1,289	1,289	2,984	2,984	-
16	Corporate Services	U20963-SA-CE-260-Coker_ATT_1, p.9	51,124	687	1,385	1,109	6,990	10,171	61,295	62,734	1,439
17	Uncollectible Expense	Exhibit No.: A-85 (KMG-4)	15,932	-	-	-	1,147	1,147	17,079	17,079	(0)
18	Injuries & Damages	Exhibit No.: A-86 (KMG-5)	2,951	-	-	-	834	834	3,785	3,785	(0)
19	Incentive Compensation	U20963-SA-CE-260-Coker_ATT_1, p.10	6,745	-	132	109	(1,246)	(1,005)	5,741	5,852	111
20	Job Work Expense	Exhibit No.: A-15 (EMB-3)	11,576	-	-	-	-	-	11,576	11,576	-
21	Interest Expense on Security Deposits	WP-JRC-31	371	-	-	-	-	-	371	371	-
22	DR Incentive/Recon	A.Griffin Testimony	-	-	-	-	1,014	1,014	1,014	1,014	-
23	Projected Inflation of Other O&M Expenses	Sum Lines 1 - 22	588,164	4,215	10,063	8,583	77,463	100,323	688,487	696,264	7,777

Question:

26. Refer to Exhibit A-44 (RTB-11). Please:

a. Expand this schedule to include a column and amounts for each line item for actual expenses in 2020 and provide in Excel.
b. For those line items where in column (k) the 2022 forecasted expense exceeds the 5-year average by more than 10%, please explain the reasons for the variance and provide the related amount for each reason.

Response:

a. Please see Attachment 1 to this discovery response. An additional new column has been inserted indicating which line items have projected 2022 spending that is more than 10% higher than the 5-year average shown in column g.

b. In my direct testimony, I compared 2022 projected O&M spending against a spending level that would by implied by inflation from 2019 actuals, which was shown in Exhibit A-47 (RTB-14). The reasons why some spending is higher than the putative inflation amount are essentially the same as why some spending is higher than the five-year average. Reasons for increases are as follows:

- For LVD Lines Reliability O&M, please refer to page 270, lines 9 through 18 of my direct testimony.
- For LVD Substations Reliability O&M, please refer to page 273, lines 3 through 8, of my direct testimony.
- For HVD Substations Reliability O&M, please refer to page 274, lines 3 through 8, of my direct testimony.
- For LVD Substations Demand, please refer to page 277, lines 12 through 17, of my direct testimony.
- For HVD Substations Demand, please refer to page 278, lines 6 through 11, of my direct testimony.
- For Staking, please refer to page 280, lines 5 through 13, of my direct testimony.
- For Meter Services (and Credits), please refer to page 281, line 14, through page 282, line 9, of my direct testimony.
- For Service Calls, the five-year average is affected by low spending in 2015 through 2017. The projected 2022 spending is in line with inflation from 2019 actual spending.
- For Meter Technology and Management System Support, the increase is due to marching the Company's Smart Energy Operation Center ("SEOC") into this line item in 2020, as stated on page 286, lines 3 through 7, of my direct testimony.

- For Smart Energy MTC, the five-year average is artificially lowered by the fact that this sub-program was new in 2017, meaning there was no spending at all in 2015 or 2016. Also please see page 287, line 18, through page 288, line 10, of my direct testimony.
- For Service Restoration, please refer to the testimony of Company witness Houtz.
- For Training, please refer to page 290, lines 1 through 11, of my direct testimony.
- For Compliance and Controls, the five-year average is artificially lowered by the fact that this sub-program was new in 2019, meaning there was no spending at all in 2015 through 2018. Projected 2022 spending is in line with inflation from 2019 actual spending.
- For Operations Performance, the five-year average is affected by low spending in 2015 and 2016 and shifting spending between the Business Services and Distribution and Generation line items. The projected 2022 spending for Operations Performance is in line with inflation from 2019 actual spending.
- For CES, projected 2022 spending is in line with inflation from 2019 spending. The five-year average is affected by lower spending in 2016 through 2018. As stated on page 296, lines 16 and 17, of my direct testimony, CES supports customer requests in the LVD Lines New Business capital sub-program, and work in that sub-program has increased since 2018.
- For LVD System Planning, please refer to page 297, line 18, through page 298, line 2, of my direct testimony.
- For HVD System Planning, please refer to page 298, lines 7 through 15, of my direct testimony.
- For Planning Analytics, the five-year average is artificially lowered by the fact that this sub-program was new in 2017. Projected spending in 2022 is in line with inflation from 2019 actual spending.
- For DER/I&C Design, this was a new sub-program in 2019. Also please see page 300, lines 12 through 18, of my direct testimony.
- For LVD Design, this was a new sub-program in 2019. Also please see page 301, lines 1 through 6, of my direct testimony.
- For Joint Pole Rental, please see page 302, lines 6 through 11, of my direct testimony.
- For Standards and Document Control, please see page 302, lines 15 through 22, of my direct testimony.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected Electric & Common O&M Expenses
For the Year 2019 & Test Year 12 Months Ending December 31, 2022
($000)

AG-GE-587

Case No.: U-20963
Exhibit No.: A-XX (RTB-11)
Page: 1 of 1
Witness: RTBlumenstock
Date: March 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)		(i)	(j)		(k)
Line No.	Description	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	5-Year Average	2020 Projected	2020 Actual	2021 Projected	2022 Projected	2022 vs. 5-Year Avg %	2022 vs. 5-Year Average
1	O&M Assoc w/Construction	4,381	7,228	6,405	8,121	8,881	7,003	-	(32)	-	-	-100%	(7,003)
2	Transformer Credits	(6,146)	(6,134)	(8,925)	(7,247)	(10,587)	(7,808)	-	0	-	-	-100%	7,808
3	**O&M Assoc w/Construction**	**(1,765)**	**1,094**	**(2,520)**	**874**	**(1,706)**	**(805)**	**-**	**(32)**	**-**	**-**		**805**
4	Lines Reliability - LVD	235	56	157	56	61	113	21	13	840	1,316	1065%	1,203
5	Lines Reliability - HVD	236	317	147	177	122	200	88	226	121	125	-37%	(75)
6	Substations Reliability - LVD	1,549	1,794	1,697	2,090	1,991	1,824	1,896	2,393	2,598	3,655	100%	1,831
7	Substations Reliability - HVD	1,069	957	1,145	1,422	1,201	1,159	1,379	1,566	2,181	2,889	149%	1,730
8	**Non-Forestry Reliability**	**3,089**	**3,124**	**3,146**	**3,745**	**3,375**	**3,296**	**3,384**	**4,198**	**5,739**	**7,985**		**4,689**
9	Lines Demand - HVD	1,167	533	785	1,681	313	896	756	527	750	988	10%	92
10	Substations Demand - LVD	3,393	3,321	2,728	3,246	3,288	3,195	2,659	2,503	2,953	4,650	46%	1,455
11	Substations Demand - HVD	2,420	2,150	2,054	2,496	2,190	2,262	2,087	2,308	2,160	3,780	67%	1,518
12	Corrective Maintenance	8,519	3,483	4,586	5,007	4,919	5,303	5,191	4,064	4,205	4,905	-8%	(398)
13	Staking	3,868	3,221	3,285	3,466	2,969	3,362	2,970	3,035	3,017	3,730	11%	368
14	Meter Services (and Credits)	5,705	2,992	437	1,020	299	2,091	(368)	(1,120)	4,699	4,383	110%	2,293
15	Streetlighting	2,153	1,933	1,637	2,206	1,759	1,938	1,669	1,680	1,156	1,752	-10%	(185)
16	Service Calls	2,451	2,108	2,839	4,172	4,708	3,256	4,150	3,871	4,410	4,999	54%	1,743
17	Alma Equipment Repair	980	1,136	1,058	1,242	982	1,080	873	699	957	1,003	-7%	(77)
18	Meter Reading	10,697	11,582	4,982	1,813	1,595	6,134	1,495	1,439	1,763	1,811	-70%	(4,323)
19	Meter Tech & Mgmt Sys Support	1,343	1,133	965	1,343	1,358	1,228	1,006	934	1,326	1,387	13%	158
20	Smart Energy MTC - Elec	-	-	7,476	7,836	8,711	4,805	8,379	8,846	9,558	9,672	101%	4,867
21	**Ops, Mtc & Mtr w/o Svc Rest**	**42,697**	**33,592**	**32,832**	**35,529**	**33,089**	**35,548**	**30,866**	**28,786**	**36,953**	**43,059**		**7,511**
22	Service Restoration - LVD	38,167	35,504	50,172	53,924	92,129	53,979	65,327	71,262	47,300	74,359	38%	20,380
23	**Service Restoration**	**38,167**	**35,504**	**50,172**	**53,924**	**92,129**	**53,979**	**65,327**	**71,262**	**47,300**	**74,359**		**20,380**
24	Training	6,047	4,174	6,075	6,160	6,376	5,766	4,439	5,366	10,247	12,609	119%	6,842
25	Tools	1,920	1,811	1,461	1,900	1,442	1,707	1,376	1,422	1,415	1,595	-7%	(112)
26	Field Operations Expenses	2,346	2,360	2,604	2,691	2,450	2,490	1,532	1,665	2,031	2,589	4%	99
27	Indirect Labor/Labor Variations	1,509	868	515	155	(516)	506	(1,538)	508	-	-	-100%	(506)
28	Supervision / Admin-Staff	6,556	6,063	6,725	7,634	7,642	6,924	5,206	5,047	4,801	6,622	-4%	(302)
29	Smart Energy Operations Center	-	-	1,166	1,183	1,036	677	430	430	-	-	-100%	(677)
30	Grid Management - Distr	2,807	2,778	4,073	4,091	3,793	3,508	3,891	3,768	4,958	5,382	53%	1,874
31	**Field Operations**	**21,185**	**18,054**	**22,619**	**23,814**	**22,224**	**21,579**	**15,337**	**18,207**	**23,452**	**28,797**		**7,218**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected Electric & Common O&M Expenses
For the Year 2019 & Test Year 12 Months Ending December 31, 2022
($000)

AG-CE-587

Case No.: U-20963
Exhibit No.: A-XX (RTB-11)
Page: 1 of 1
Witness: RTBlumenstock
Date: March 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)		(i)	(j)		(k)
Line No.	Description	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	5-Year Average	2020 Projected	2020 Actual	2021 Projected	2022 Projected	2022 vs. 5-Year Avg %	2022 vs. 5-Year Average
32	Compliance and Controls	-	-	-	-	1,635	327	1,433	1,433	1,612	1,792	448%	1,465
33	**Compliance and Controls**	**-**	**-**	**-**	**-**	**1,635**	**327**	**1,433**	**1,433**	**1,612**	**1,792**		**1,465**
34	Resource Planning & Closeout	-	39	495	365	325	245	203	204	193	197	-19%	(48)
35	Scheduling & Dispatch	3,249	3,605	5,273	5,390	4,895	4,482	4,059	4,053	4,430	4,790	7%	308
36	Contract Administration	-	229	353	345	254	236	181	151	196	200	-15%	(36)
37	**Planning & Scheduling**	**3,249**	**3,873**	**6,121**	**6,100**	**5,474**	**4,963**	**4,442**	**4,407**	**4,819**	**5,188**		**224**
38	OP Distribution & Generation	361	722	1,552	677	1,507	964	1,448	1,315	1,670	1,705	77%	742
39	OP Business Services	230	255	202	1,229		479					-100%	(479)
40	**Operations Performance**	**591**	**977**	**1,754**	**1,906**	**1,507**	**1,347**	**1,448**	**1,315**	**1,670**	**1,705**		**358**
41	**Operations Management**	**3,415**	**2,640**	**1,167**	**1,673**	**1,420**	**2,063**	**2,570**	**2,381**	**1,534**	**1,568**	-24%	**(495)**
42	**Ops IT Projects**							**-**	**-**	**648**	**570**		
43	**Total Electric Operations**	**110,628**	**98,858**	**115,291**	**127,566**	**159,147**	**122,298**	**124,806**	**131,957**	**123,726**	**165,023**		**42,725**
44	Strategy	-	-	57	102	96	51		-			-100%	(51)
45	Regulatory & Compliance-Elec	168	170	140	151		157		-			-100%	(157)
46	CES	499	360	354	362	428	400	416	381	432	445	11%	44
47	**Engineering Support**	**667**	**529**	**550**	**616**	**524**	**577**	**416**	**381**	**432**	**445**		**(132)**
48	Geospatial Mgmt & Data Quality - E	253	385	598	107		336					-100%	(336)
49	Planning - LVD System	3,190	1,797	2,183	3,103	3,966	2,848	3,304	2,999	6,876	6,666	134%	3,818
50	Planning - HVD System	2,715	3,270	3,972	3,139	3,150	3,249	3,476	3,335	3,778	4,236	30%	987
51	System Protection	2,828	2,549	1,425	1,951	1,370	2,025	1,208	1,305	1,279	1,638	-19%	(387)
52	Planning Analytics	-	-	420	521	1,107	410	1,963	1,940	678	1,209	195%	799
53	**Electric Planning**	**8,986**	**8,001**	**8,598**	**8,821**	**9,593**	**8,800**	**9,951**	**9,579**	**12,611**	**13,748**		**4,948**
54	Design - DER / I&C	-	-	-	-	279	56	203	124	442	619	1011%	563
55	Design - LVD	-	-	-	-	933	187	395	381	372	921	393%	734
56	Design - HVD	1,522	1,209	1,287	1,544	1,090	1,330	566	546	750	1,307	-2%	(24)
57	Joint Pole Rental	1,791	1,789	1,805	1,857	1,975	1,844	2,199	2,200	2,239	2,351	28%	507
58	Standards & Document Control	179	151	353	247	471	280	412	410	508	626	123%	346
59	**Electric Design**	**3,492**	**3,149**	**3,445**	**3,648**	**4,748**	**3,696**	**3,775**	**3,662**	**4,311**	**5,823**		**2,127**
60	**Electric Engineering & Support**	**13,144**	**11,679**	**12,593**	**13,084**	**14,865**	**13,073**	**14,142**	**13,622**	**17,354**	**20,016**		**6,943**
61	**Total O&M**	**123,772**	**110,537**	**127,884**	**140,650**	**174,012**	**135,371**	**138,948**	**145,579**	**141,080**	**185,039**		**49,668**

U20963-AG-CE-867
Page **1** of **1**

Question:

26. Refer to Figure 1 on page 3 of Ms. Houtz's direct testimony. Please:

a. Expand this table to include the same information for each year actuals for 2015, 2016, 2017 and 2020, and provide it in Excel with formulas intact.

b. Explain what inflation factors were applied by line item to determine the 2021 and 2022 expense level.

c. Explain why the service restoration expense declined in 2020 from 2019 if, as claimed by the Company, winds are now blowing stronger and more storms have occurred in recent years.

Response:

a. See Attachment U20963-AG-CE-867-Houtz_Att_1

b. Inflation rates are listed below:

Inflation Rates

Other Labor	3.2%	103.2%
OM&C Labor	3.0%	103.0%
Non-Labor 2021	2.5%	102.5%
Non-Labor 2022	2.3%	102.3%

c. In 2019, the Company responded to 2 catastrophic events that reached an ICS level 3 and 9 MEDs.

In 2020, the Company responded to 1 catastrophic event that reached an ICS level 3 and 8 MEDs.

The reduction in catastrophic events/MEDs in 2020 is the reason for the decline in service restoration expense.

Service restoration costs are volatile due to weather patterns and the Company has accounted for the potential in years that see fewer weather events by proposing a two-way deferral mechanism in this case.

Brenda L. Houtz
May 28, 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CECo Response to AG-CE-867

Case No: U-20963
Exhibit: AG-1.49
June 22, 2021

Last Updated: 4/20/2021 AG-CE-867

Service Restoration Actuals 2015 - 2020

	2015	2016	2017	2018	2019	2020 (9 + 3 FC)	Grand Total	3 Year Avg (2018 - 2020)	Inflated 2021	Inflated 2022		2020 Actuals
Business Expense	$151,322	$124,669	$448,375	$158,726	$329,863	$116,445	$1,329,401	**$201,678**	**$206,720**	**$211,475**		133,560
Contractor	$15,559,075	$9,247,355	$24,208,233	$18,962,523	$39,018,235	$25,276,697	$132,272,118	**$27,752,485**	**$28,446,297**	**$29,100,562**		26,982,472
Exempt Labor	$1,132,544	$1,050,640	$2,919,993	$1,883,210	$3,780,786	$2,224,137	$12,991,310	**$2,629,378**	**$2,713,518**	**$2,800,350**		2,650,666
Material	$419,034	$910,278	$1,048,076	$1,300,668	$2,061,898	$1,461,370	$7,201,324	**$1,607,979**	**$1,648,178**	**$1,686,086**		1,531,972
Non Exempt Labor	$1,008,758	$752,670	$1,600,151	$1,702,025	$2,132,696	$961,600	$8,157,900	**$1,598,774**	**$1,649,935**	**$1,702,732**		1,129,920
OM&C Labor	$7,466,163	$7,462,007	$12,772,881	$12,604,957	$18,152,878	$12,905,381	$71,364,267	**$14,554,405**	**$14,991,037**	**$15,440,769**		14,907,644
Other Expense	$7,044,720	$5,920,941	($4,184,918)	$7,966,426	$9,667,000	$7,280,171	$33,694,340	**$8,304,532**	**$8,512,146**	**$8,707,925**		8,286,916
Other Labor	$5,385,096	$10,035,482	$11,359,171	$9,345,523	$16,985,282	$15,101,198	$68,211,752	**$13,810,668**	**$14,252,609**	**$14,708,692**		15,638,991
Grand Total	$38,166,712	$35,504,042	$50,171,961	$53,924,058	$92,128,638	$65,327,000	$335,222,411	**$70,459,899**	**$72,420,440**	**$74,358,592**		71,262,140

Five Year Average: 2016 to 2020 Actual **$ 60,598,168**

*Includes Insurance Recovery

Inflation Rates		
Other Labor	3.2%	103.2%
OM&C Labor	3.0%	103.0%
Non-Labor 2021	2.5%	102.5%
Non-Labor 2022	2.3%	102.3%

Question:

28. Refer to page 8 of Ms. Houtz's direct testimony. Please:
    a. Confirm that the Pre-Staging activities described in this testimony have not changed from the new Pre-Staging activities described in your testimony in Case No. U-20697. If not confirming, please explain any changes that were made.
    b. Provide the number of employees involved in Pre-Staging activities in each year 2016 to 2020 and forecasted for 2021 and 2022.
    c. Identify the costs incurred for Pre-Staging activities in each year 2016 to 2020 and forecasted for 2021 and 2022. Identify in which line items these costs are reflected in Figure 1 on page 3 of your testimony.

Response:

a. Pre-staging has not changed from U-20697 to U-20963.

b. The Company does not have employee count data for pre-staging activities in the years of 2016-2019. The Company began tracking this data in 2020 for salaried/office employees only. Tracking for OM&C employees began in 2021.

Pre-Staging Employee Count			
Employee Type	**2020 actual**	**2021 forecast**	**2022 forecast**
Exempt Labor Non-exempt Labor	883	1,733*	1,733*
OM&C Labor	*(not available)*	627*	627*
Contractor*	2,500*	2,500*	2,500*

**This information is an estimate and is dependent upon weather.*

The Contractor employee count number listed above is an estimate based on the number of Contractor Crews the Company has documented in its records. In total, 852 Contractor Crews were used throughout 2020. The Company estimates each Crew is made up of at least 3 FTEs (but could be more).

c. The Company does not have cost data for pre-staging activities in the years of 2016-2019. The Company began tracking this data in 2020 for salaried/office employees only. Tracking for OM&C employees began in 2021.

Pre-Staging Costs			
Employee Type	**2020 actual**	**2021 forecast**	**2022 forecast**
Exempt Labor Non-exempt Labor	$914,348	$972,550*	$972,550*
OM&C Labor	*(not available)*	$181,000*	$181,000*
Contractor*	$562,500*	$562,500*	$562,500*

**This information is an estimate and is dependent upon weather.*

The employee type in the prestaging costs table above map to the expense category listed below.

1) Exempt Labor and Non-exempt Labor listed in the Pre-Staging Costs table above are in the line items Exempt Labor and Non-Exempt Labor shown below.
2) OM&C Labor listed in the Pre-Staging Costs table above is in the line item OM&C Labor shown below.
3) Contractor listed in the Pre-Staging Costs table above is in the line item Contractor Labor shown below.

	2018	2019	2020 (9 + 3 FC)	Grand Total	3 Year Avg (2018 - 2020)	Inflated 2021	Inflated 2022
Business Expense	$158,726	$329,863	$116,445	$1,329,401	**$201,678**	**$206,720**	**$211,475**
Contractor	$18,962,523	$39,018,235	$25,276,697	$132,272,118	**$27,752,485**	**$28,446,297**	**$29,100,562**
Exempt Labor	$1,883,210	$3,780,786	$2,224,137	$12,991,310	**$2,629,378**	**$2,713,518**	**$2,800,350**
Material	$1,300,668	$2,061,898	$1,461,370	$7,201,324	**$1,607,979**	**$1,648,178**	**$1,686,086**
Non Exempt Labor	$1,702,025	$2,132,696	$961,600	$8,157,900	**$1,598,774**	**$1,649,935**	**$1,702,732**
OM&C Labor	$12,604,957	$18,152,878	$12,905,381	$71,364,267	**$14,554,405**	**$14,991,037**	**$15,440,769**
Other Expense	$7,966,426	$9,667,000	$7,280,171	$33,694,340	**$8,304,532**	**$8,512,146**	**$8,707,925**
Other Labor	$9,345,523	$16,985,282	$15,101,198	$68,211,752	**$13,810,668**	**$14,252,609**	**$14,708,692**
Grand Total	$53,924,058	$92,128,638	$65,327,000	$335,222,411	**$70,459,899**	**$72,420,440**	**$74,358,592**

Brenda Houtz

Brenda L. Houtz
May 28, 2021

Grid Management

U20963-AG-CE-870
Page **1** of **1**

Question:

29. Refer to page 14, lines 6-7 of Ms. Houtz's direct testimony. Please provide a reference to testimony or an exhibit where it shows that the new Pre-Staging activities have had a beneficial impact on costs, restoration time, etc.

Response:

Please refer to Houtz's direct testimony, page 10, lines 2-13 for an example of the Company's response to an icing event where the Company used pre-staging. See the following for the Company's performance in this event:

MPSC Performance Metrics	Standard	Actual Performance
8-hour normal by	> 90%	95.1%
36-hour normal by	> 90%	100%
Police & Fire wire downs secured within 4 hours (inside MMSA)	> 90%	100%
Police & Fire wire downs secured within 6 hours (outside MMSA)	> 90%	100%

In addition, the Company restored critical and priority customers in 141 minutes on average, police and fire relieved in 62 minutes on average, and achieved 172 CAIDI minutes and 3.95 SAIDI minutes during this event.

Brenda Houtz

Brenda L. Houtz
May 28, 2021

Grid Management

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

Question:

11. Refer to page 26, lines 1-2 of Ms. Bolden's direct testimony. Exhibit A-54 shows a 25% decrease in tree-related outages from 2019/2020 to 2025 but a 122% increase in required funding to achieve that reduction. The cumulative incremental spending from 2019/2020 to 2025 is $66.3 million, which translates to a cost of $24,348 per avoided outage ($66.3 million / 2,723). This result appears to be a very costly approach to achieve a relatively small number of avoided outages. Is the Company being conservative in setting a goal to reduce tree-related outages? Please explain why the incremental spending is reasonable.

> **Objection of Counsel: Consumers Energy Company objects to this discovery request on the basis that it attempts to characterize Ms. Bolden's testimony, it relies on its own untested analysis, and is argumentative. Without waiving this objection, the Company responds as follows:**

Response:

The Company is presenting in this case its best estimate of reliability impacts and is neither being conservative nor liberal in its estimates. To be clear, the direct testimony of Company witness Bolden is discussing outage incidents and not customer outages. Using the data presented in WP-PLB-3 for primary related tree-caused outages (substation/circuit/primary), the total customer outages from 2014 through 2019 is 4,959,582 divided by the total primary outage incidents of 48,883 results in an average of 101.46 customers per tree-related primary outage incident. Therefore, 2,723 reduced primary outage incidents multiplied by 101.46 customers per primary outage results in approximately 276,275 reduced customer outages or $228 per reduced customer outage (LVD system 2025 projected at 7-year cycle $106.520M minus 2019-2020 LVD system average $43.591M equals $62.929M incremental spend divided by 276,275 reduced customer outages). The Company believes this is reasonable.

Pamela L. Bolden
PAMELA L. BOLDEN
May 24, 2021

HVD and Forestry Management

U20963-AG-CE-853
Page **1** of **2**

Question:

12. Refer to Exhibit A-53 (PLB-1). Please:

a. Provide this schedule in Excel expanded to include actuals for 2015, 2016 and 2020.

b. Explain why HVD cost per mile decreased in 2020 from 2019 and is increasing in 2021. Provide detailed support for your reasons.

c. Explain why LVD costs per mile are increasing by 24% from 2020 to 2021, and 17% from 2019. Provide detailed support for your reasons.

d. For each year 2016 to 2020, please provide a comparison of the miles and costs forecasted for tree clearing in the applicable rate cases and the amount actually completed and spent.

Response:

a. Exhibit A-53 (PLB-1) revised for this response is attached (U20963-AG-CE-853-Bolden_ATT_1).

b. In November 2018 the Company executed new contracts with the major line clearing contractors working on the LVD and HVD systems. This contract established a minimum pay scale for contractor crew positions. This increase was necessary as surrounding utilities had much higher pay scales and contractor crew retention on the Company system was necessary to develop a skilled and productive workforce for the 2021 spending ramp-up. The retention of crew personnel increased productivity resulting in a decreased cost per mile, offsetting the minimum wage requirement in the contract. Late in 2020 and continuing in 2021 the Company has added new contractors to the system, focusing on smaller Michigan-based businesses. These new contractors have billing rates approximately 17.1% higher than our base contractors. The base contractors have also added additional crews to meet completed miles and spending targets. These new crews (new contractors and expanded base contractor crews) are less productive while training and skill development occurs, resulting in increased cost per mile.

c. Please see b. above.

d. The Company proposed line clearing costs and miles targets in rate cases during this timeframe were not approved by the MPSC and therefore, it is irrelevant to compare rate case proposed targets that were not approved to actuals. Below are the MPSC approved rate case spending amounts for line clearing and the YE actuals. The Company has consistently exceeded the rate case authorized amounts for line clearing during this timeframe. Completed mileage targets were not set for the authorized spending amounts in these rate cases.

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Page **2** of **2**

Comparison of Actual Line Clearing Expenses versus Rate Case Authorized Spending Levels					
Year	2016	2017	2018	2019	2020
Applicable MPSC Case Numbers	U17735	U17735 & U17990	U17990 & U18322	U18322 & U20134	U20134
MPSC Authorized Line Clearing Costs	$48,500,000	$48,500,000	$51,004,380	$51,800,000	$51,800,000
YE Actual Spend	$50,781,573	$49,753,866	$51,948,358	$53,289,931	$55,274,435
Amount Spent Above Rate Case Authorized	$2,281,573	$1,253,866	$943,978	$1,489,931	$3,474,435
YE Completed Miles	5,044	4,522	4,299	4,620	5,327

Pamela L. Bolden

PAMELA L. BOLDEN
May 25, 2021

HVD and Forestry Management

MICHIGAN PUBLIC SERVICE COMMISSION

AG-CE-853

Case No.: U-20963
Exhibit No.: A-53 (PLB-1 Revised AG-CE-853)
Page: 1 of 1
Witness: PLBolden
Date: March 2021

Consumers Energy Company
Line Clearing O&M Expense
2015-2020 Historic Actuals/2019 and 2020 9-Months Actual + 3-Months Projected/2021-2026 Forecast

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Electric System	Expense Type	Year	2015	2016	2017	2018	2019	2019	2020	2020	2021	2022	2023	2024	2025	2026
				Actual	Actual	Actual	Actual	9+3 Projected	Actual	9+3 Projected	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
2	**Electric HVD**			**$6,277,258**	**$9,517,154**	**$11,393,937**	**$12,035,797**	**$11,474,854**	**$12,211,819**	**$9,475,000**	**$9,169,947**	**$12,600,000**	**$12,870,000**	**$13,190,000**	**$13,510,000**	**$13,835,000**	**$14,178,000**
3		Contractor	Maintenance Clearing	$3,984,789	$5,880,139	$7,658,022	$8,438,081	$7,390,660	$7,571,492	$4,704,000	$4,511,969	$6,955,000	$7,130,000	$7,300,000	$7,480,000	$7,665,000	$7,855,000
4		Contractor	Brushing - Cut	$1,479,310	$2,495,403	$2,388,351	$2,682,986	$3,296,287	$3,823,127	$2,516,000	$2,365,927	$2,400,000	$2,460,000	$2,520,000	$2,585,000	$2,650,000	$2,718,000
5		Contractor	Brushing - Spray	N/A	N/A	N/A	N/A	N/A	N/A	$1,390,000	$1,395,683	$2,310,000	$2,320,000	$2,390,000	$2,450,000	$2,505,000	$2,565,000
6		Contractor	Demand Clearing	$217,463	$348,198	$375,620	$152,548	$84,242	$87,281	$85,000	$110,249	$75,000	$75,000	$75,000	$65,000	$60,000	$55,000
7		Contractor	Noxious Weed Control	$36,399	$32,432	$20,546	$70,093	$24,009	$52,416	$95,600	$91,873	$40,000	$45,000	$45,000	$50,000	$50,000	$55,000
8		Labor	HVD Salaries [1]	$436,612	$599,308	$709,395	$666,847	$653,501	$650,467	$665,000	$672,387	$760,000	$775,000	$790,000	$810,000	$830,000	$845,000
9		Other	HVD Expenses [1]	$122,685	$161,674	$242,003	$25,242	$26,155	$27,036	$19,400	$21,859	$60,000	$65,000	$70,000	$70,000	$75,000	$85,000
10			**Miles**	**734**	**1,093**	**1,019**	**1,081**	**1,064**	**1,102**	**1,103**	**1,116**	**1,129**	**1,131**	**1,134**	**1,136**	**1,138**	**1,140**
11	**Electric LVD**			**$30,735,025**	**$41,264,419**	**$38,359,929**	**$39,912,561**	**$41,525,147**	**$41,078,112**	**$45,275,000**	**$46,104,488**	**$71,430,000**	**$81,485,000**	**$86,840,000**	**$104,100,000**	**$106,520,000**	**$106,520,000**
12		Contractor	Maintenance Clearing	$23,634,234	$31,731,669	$29,372,207	$31,038,484	$33,481,817	$32,173,215	$36,126,000	$36,613,687	$54,890,000	$64,037,000	$68,361,000	$84,157,000	$86,640,000	$86,640,000
13		Contractor	Repetitive Outage Zone	$1,031,691	$1,762,582	$934,465	$2,054,288	$795,749	$995,575	$1,461,000	$1,397,354	$2,000,000	$1,900,000	$1,700,000	$1,500,000	$1,350,000	$1,215,000
14		Contractor	CEMI Clearing	N/A	N/A	N/A	N/A	N/A	N/A	$561,000	$695,322	$1,000,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000
15		Contractor	First Zone Clearing	$0	$169,130	$399,793	$102,600	$1,172,518	$1,523,542	$779,000	$974,275	$1,875,000	$1,975,000	$2,175,000	$2,375,000	$2,525,000	$2,660,000
16		Contractor	Demand Clearing	$2,682,845	$2,923,814	$2,642,665	$1,444,228	$1,541,213	$1,695,571	$1,206,000	$1,281,844	$2,735,000	$2,673,000	$2,614,000	$2,558,000	$2,505,000	$2,505,000
17		Contractor	Brushing - Spray	$647,808	$1,621,820	$1,807,622	$1,679,301	$788,688	$989,772	$1,542,000	$1,538,898	$2,900,000	$2,900,000	$3,190,000.0	$3,510,000.0	$3,500,000	$3,500,000
18		Labor	Distribution Salaries [1]	$2,137,751	$2,406,272	$2,388,399	$2,532,425	$2,671,931	$2,683,107	$2,517,000	$2,509,359	$4,305,000	$4,640,000	$5,210,000	$6,070,000	$6,070,000	$6,070,000
19		Other	Distribution Expenses [1]	$600,696	$649,132	$814,778	$1,061,235	$1,073,231	$1,017,330	$1,083,000	$1,093,749	$1,725,000	$1,860,000	$2,090,000	$2,430,000	$2,430,000	$2,430,000
20			**Miles**	**3,633**	**3,951**	**3,503**	**3,218**	**3,106**	**3,518**	**4,120**	**4,211**	**5,223**	**5,986**	**6,346**	**7,654**	**7,914**	**7,918**
21	**Electric Total**		**O&M Expense**	**$37,012,283**	**$50,781,573**	**$49,753,866**	**$51,948,358**	**$53,000,001**	**$53,289,931**	**$54,750,000**	**$55,274,435**	**$84,030,000**	**$94,355,000**	**$100,030,000**	**$117,610,000**	**$120,355,000**	**$120,698,000**
22		Contractor	Clearing	$33,714,539	$46,965,187	$45,599,291	$47,662,609	$48,575,183	$48,911,991	$50,465,600	$50,977,081	$77,180,000	$87,015,000	$91,870,000	$108,230,000	$110,950,000	$111,268,000
23		Labor	Salaries	$2,137,751	$2,406,272	$3,097,794	$3,199,272	$3,325,432	$3,333,574	$3,182,000	$3,181,746	$5,065,000	$5,415,000	$6,000,000	$6,880,000	$6,900,000	$6,915,000
24		Other	Expenses	$600,696	$649,132	$1,056,781	$1,086,477	$1,099,386	$1,044,366	$1,102,400	$1,115,608	$1,785,000	$1,925,000	$2,160,000	$2,500,000	$2,505,000	$2,515,000
25			**O&M Miles**	**4,367**	**5,044**	**4,522**	**4,299**	**4,170**	**4,620**	**5,223**	**5,327**	**6,352**	**7,117**	**7,480**	**8,790**	**9,052**	**9,058**
26			HVD Cost/Mile	$8,552	$8,707	$11,181	$11,134	$10,785	$11,082	$8,590	$8,217	$11,160	$11,377	$11,636	$11,895	$12,157	$12,433
27			LVD Cost/Mile	$8,460	$10,444	$10,951	$12,403	$13,369	$11,677	$10,989	$10,949	$13,676	$13,613	$13,684	$13,600	$13,460	$13,453
28			LVD Target Cycle Miles	8,362	8,362	8,362	8,362	8,362	8,362	8,362	8,362	8,362	8,362	8,362	8,362	8,362	8,362
29			LVD O&M Program Miles	3,633	3,951	3,503	3,218	3,106	3,518	4,120	4,211	5,223	5,986	6,346	7,654	7,914	7,918
30			Capital Clearing Miles	~620	~530	442	489	340	301	430	258	500	525	515	500	475	425
31			Percent of 7 Year Cycle	51%	54%	47%	44%	41%	46%	54%	53%	68%	78%	82%	98%	100%	100%
32	Note 1 - 2015-2017 Salaries and Expense cost are allocations of the total Salaries and Expense costs by the percentage of contractor costs for each sub-program (LVD and HVD)																

U20963-AG-CE-781
Page **1** of **1**

Question:

12. Refer to Exhibit A-95 (SAH-5), page 1 and 3. Please provide the same schedules in Excel with actual 2020 costs.

Response:

Please see Attachment U20963-AG-CE-781_ATT_1 for 2020 actual costs for Exhibit A-95 (SAH-5), pages 1 and 3.

Scott A. Hugo
May 25, 2021

Director – Generation Asset Strategy

MICHIGAN PUBLIC SERVICE COMMISSION						Case No.:	
			AG-CE-781			Exhibit No.:	
Consumers Energy Company						Page:	
Summary of the Generation O&M Expense						Witness:	SAHugo
For the Years 2019 through 2022						Date:	May 2021
($000's)							

GENERATION OPERATION AND MAINTENANCE EXPENSES

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical	**Historical**	**Projected Bridge Year**		**Projected Test Year**
Line		**12 Months Ended**	**12 Months Ended**	**12 Months Ended**	**12 Months Ending**	**12 Months Ending**
No.	Description	**12/31/2019**	**12/31/2020**	**12/31/2020**	**12/31/2021**	**12/31/2022**
1	**BASE O&M**	$ 96,804	$ 106,821	$ 98,335	$ 109,119	$ 119,321
2	**ADJUSTED O&M**					
3	Environmental Operations	$ 10,485	$ 8,595	$ 9,071	$ 8,649	$ 8,798
4	Major Maintenance	$ 19,804	$ 25,088	$ 24,783	$ 32,667	$ 28,544
5	Karn Retention & Separation	$ 5,921	$ 12,028	$ 12,345	$ 7,497	$ 5,177
6	**TOTAL O&M**	**$ 133,015**	**$ 152,533**	**$ 144,534**	**$ 150,434**	**$ 156,662**

U20963-AG-CE-954
Page **1** of **1**

Question:

17. Refer to page 23, lines 14-16 of Ms. Anita Griffin's direct testimony. Please:
a. Explain the reasons for the decrease in the expense.
b. Provide the number of employees and contractors working in this area in each year 2019 to 2022 at year end and identify what specifically they do.

Response:

A. The reason for the decrease to the O&M spending for the test year ending December 2022 is due to a change in how analytics and outreach work is charged. In 2019, the services provided for this team, including labor dollars were paid for with O&M dollars. In 2022, there has been a shift to charging the organizations that utilize the services of analytics and outreach, therefore less O&M budget is needed.

The below table reflects the total headcount in the marketing area for the given year. The financial exhibits reflect the portion of employee labor that supports utility O&M efforts. The remainder is reflected in various projects and/or products through direct charging to other business areas.

B:

2019	18 employees 5.5 contractors	4: Customer Research 3: Customer Data & Analytics 8: Marketing Strategy (outreach) 3: leadership, administrative and operations 5.5 contractors: Customer Data & Analytics
2020	33 employees 7 contractors	4: Customer Research 5: Customer Data & Analytics 21: Marketing Strategy (outreach) 3: leadership, administrative and operations 7 contractors: Customer Data & Analytics
2021	46 employees 7 contractors	5: Customer Research 16: Customer Data & Analytics 22: Marketing Strategy (outreach) 3: leadership, administrative and operations 7 contractors: 6 Customer Data & Analytics 1 Marketing strategy(outreach)
2022	46 employees 7 contractors	5: Customer Research 16: Customer Data & Analytics 22: Marketing Strategy (outreach) 3: leadership, administrative and operations 7 contractors: 6 Customer Data & Analytics 1 Marketing strategy(outreach)

Anita J. Griffin
June 4, 2021

MICHIGAN PUBLIC SERVICE COMMISSION

Exhibit AG-1.54

Consumers Energy Company - Electric Rate Case

Case No: U-20963

June 22, 2021

Electric Uncollectible Accounts Expense for 2022

($000)

Line No.	(a) Year	(b) Gross Charge-Offs	(c) Less Recoveries	(d) Net Write-Offs	(e) Total Electric Service Revenue MPSC P-521 P. 304.1 col (c) + P. 305 col (c)	(f) BDLR col (d) / col (e)
1	2015	$ 46,941	$ 16,886	$ 30,055	$ 4,031,759	0.745%
2	2016	32,691	13,496	19,195	$ 4,157,271	0.462%
3	2017	32,032	13,060	18,972	$ 4,245,558	0.447%
4	2018	28,943	12,282	16,661	$ 4,382,878	0.380%
5	2019	27,032	11,100	15,932	$ 4,249,553	0.375%
6	2020	22,393	11,965	$ 10,428	$ 4,147,450	0.251%
7	3-Year Average (2018-2020)	$ 26,123	$ 11,782	$ 14,340	$ 4,259,960	0.337%
8	5-Year Average (2016-2020)	$ 28,618	$ 12,381	$ 16,238	$ 4,236,542	0.383%
9	Test Year Total Company Electric Revenues and Deliveries					
10	Exhibit A-15 (EMB-3), Schedule E-2, Page 1 of 1					
11	Row 25, Column (I) - Row 25, Column (c)				$ 4,215,555	
12	3-Year Average BDLR				0.337%	
13	Test Year Total Uncollectible Accounts Expense				**$ 14,191**	
14	Company Calculated Uncollectible Expense				17,079	
15	**Disallowance Amount**				**$ (2,888)**	

Source: CECo Response to MEC-CE-403a.

U20963-AG-CE-856
Page **1** of **1**

Question:

15. Refer to page 4, lines 11-13 of Mr. Underwood's direct testimony. Please provide more detail and support as to how he arrived at the escalation rates for 2021 and 2022 for each insurance policy listed in Exhibit A-113 (DTU-1). Provide any calculations in Excel with formulas intact.

Response:

A discussion of the escalation rate is provided in my testimony on page 4, lines 12-18.

TIM UNDERWOOD
May 24, 2021

Risk Department

U20963-AG-CE-864
Page **1** of **2**

Question:

23. Refer to Exhibit A-83 (KMG-2). Please:

a. Provide the same information for actual for each year 2016 to 2018 in Excel. Separately identify the amount of insurance premiums and refunds/distributions received each year 2016 to 2020 and included on line 3.

b. Provide the number of employees for each function on lines 2-8 at each year end 2016 to 2020 and forecasted for 2021 and 2022. Explain the reasons for any increases in employees in 2019, 2020, 2021 and 2022 from the prior year.

c. Provide the calculation supporting the $715,000 on line 10, column (m).

Response:

a. See attachment U20963-AG-CE-864-Gaston_ATT_1 for Exhibit A-83 with years 2016 - 2018 actual expenses included as requested. See below for the separate table of insurance premium expense and refunds/distributions by year for 2016 through 2020 included in line 3 of U20963-AG-CE-864-Gaston_ATT_1.

	2016	2017	2018	2019	2020
Insurance Premium expense	16,292,855	16,030,172	17,543,327	16,718,821	15,715,197
Refunds/Distributions	(3,858,353)	(3,754,317)	(10,893,094)	(7,117,180)	(13,861,120)

b. See table below for the number of employees at year end by function for years 2016 through 2020.

Department/Function	**2016 Headcount**	**2017 Headcount**	**2018 Headcount**	**2019 Headcount**	**2020 Headcount**	**2021 Projected**	**2022 Projected**
Gov't Reg. & Public Aff.	98	98	97	101	95	101	101
Gen. Counsel, Leg. & Risk	81	80	80	79	66	79	79
HR & Learning & Dev	218	206	195	202	193	202	202
Transform. & Ops Supp.	54	39	47	46	31	46	46
Chief Financial Officer	168	223	238	235	226	235	235
Strategy	26	8	14	13	14	13	13
General Activities	3	7	4	4	7	4	4
Total Corporate	**648**	**661**	**675**	**680**	**632**	**680**	**680**
Year over year change				+5	(48)	+48	0

Comparison	**Increase**	**Reason**
2018 vs 2019	+5	The increase was driven due to expanding the Diversity, Equity and Inclusion and Leadership and Organizational Development teams within the Human Resources department.
2020 vs 2021	+48	2021 headcount projection is based on the assumption that headcount will remain at 2019 levels. Actual headcount in 2020 was unusually low due to a voluntary separation and hiring freeze as a result of the COVID-19 pandemic.

Please note, there have been reorganizations within and amongst corporate departments that have resulted in headcount changes between departments. Costs in the exhibit align with the reorganized department headcounts and not the headcount as of the end of the year as represented above. In addition, headcount above represents responsibility or whole employee counts by department.

c. The calculation to support the $715,000 on line 10, column (m) is as follows:

	Amount	**Notes**
2020 EICP accrual	3,556,653	Based on 100% payout
Less: 2019 EICP actual expense	4,271,332	Actual payout was greater than 100%
Adj. line 10, col. (m)	**(714,679)**	

Each year, EICP is accrued for based on an assumed 100% payout. When goal performance is greater than 100%, the actual expense in a historical year can be greater than the amount accrued for. This exhibit provides the actual EICP expense in the historical year (2019) and assumes EICP payout at 100% for projected years 2021 through 2022.

Karen M. Gaston
May 28, 2021

Budget, Planning & Analysis

Question:

18. Refer to Exhibit A-113 (DTU-1). Please:

a. The Excel version of this exhibit provided by the Company does not have formulas showing the build-up of the amounts in each column. Please provide an Excel version with formulas intact showing the build-up of expense from column to column.

b. Explain how the portion of premiums allocated to the electric business for each policy was determined and provide the allocation factor.

c. What do the asterisk footnotes pertain to?

d. Provide the actual premiums paid and the amount allocated to the electric business for each coverage policy listed in this exhibit for each year 2016 to 2020. Identify the amount for new coverages added and removed from the prior year with the related premium changes and explain the reason for the change. Provide this information in Excel with formulas intact.

Response:

a. See attached excel spreadsheet – U20963-AG-CE-859-Underwood-ATT_1.

b. Below is the method for allocating a portion of the insurance invoice to the electric business:

Main Property (incl terrorism) – based on breakdown provided by the insurer. Approximately 83% of the 2020 total invoice was allocated to electric.

Lake Winds; Cross Winds; Gratiot Wind; and Crescent Wind – the premium charged is 100% allocated to electric since these are the only plants insured on the policies.

Solar Energy – is the total insured value for Consumers' solar plants compared to total insured value of all insured plants. Approximately 21% of the 2020 total invoice was allocated to electric.

Fidelity/Crime – the total invoice is subject to the Massachusetts Allocation method. For 2020 the allocation was 95.5% to the utility and 4.5% to the non-utility. Of the 95.5% allocated to the utility 50% was allocated to electric.

Spare Transformer – the premium charged is 100% allocated to electric since it is electric equipment.

General Liability (incl professional) – the total invoice is subject to the Massachusetts Allocation method. For 2020 the allocation was 95.5% to the utility and 4.5% to the non-utility. Of the 95.5% allocated to the utility 50% was allocated to electric.

Railroad Protective Liability – 50% is allocated to electric.

Fiduciary Liability - the total invoice is subject to the Massachusetts Allocation method. For 2020 the allocation was 95.5% to the utility and 4.5% to the non-utility. Of the 95.5% allocated to the utility 51% was allocated to electric.

Workers' Comp – 50% is allocated to electric.

WC Self-Insured Bond – 50% is allocated to electric.

Workers' Comp (Multi-States) – 50% is allocated to electric.

Workers' Comp (Ohio) – 50% is allocated to electric.

D&O Liability – the total invoice is subject to the Massachusetts Allocation method. For 2020 the allocation was 95.5% to the utility and 4.5% to the non-utility. Of the 95.5% allocated to the utility 50% was allocated to electric.

Cyber Liability – 5% of the total invoice is allocated to EnerBank based on their percentage of revenue compared to total revenue of all insured entities and the remaining 95% is subject to the Massachusetts Allocation method. For 2020 the allocation was 95.5% to the utility and 4.5% to the non-utility. Of the 95.5% allocated to the utility 50% was allocated to electric.

D&O Special – the total invoice is subject to the Massachusetts Allocation method. For 2021 the allocation was 94.1% to the utility and 5.9% to the non-utility. Of the 94.1% allocated to the utility 50% was allocated to electric.

Non-Owned Aircraft Liability – 51% is allocated to electric.

Nuclear Liability – 100% is allocated to electric.

c. The asterisks were intended to show that a portion of the workers' comp premium was allocated to capital and not included as O&M expense. These amounts are shown in the attached excel file.

d. See attached excel file U20963-AG-CE-859-Underwood-ATT_2.

TIM UNDERWOOD
May 25, 2021

Risk Department

2021 Premiums for Electric Operations (with 2016 - 2020 invoice totals and calculations) AG-CE-859

Insurance	2016 Renewal Total Premium Invoice	2016 Elec Portion	2017 Renewal Total Premium Invoice	2017 Elec Portion	2018 Renewal Total Premium Invoice	2018 Elec Portion	2019 Renewal Total Premium Invoice	2019 Elec Portion	2020 Renewal Total Premium Invoice	2020 Elec Portion
(The following 2 lines are consolidated into "Main Property" on the exhibit)										
Main Property (incl terrorism) [1]	6,232,065	5,326,569	6,417,027	5,540,745	7,542,241	6,394,925	6,846,374	5,754,804	7,786,066	6,583,901
Business interruption [2]	252,559	252,559	304,428	304,428	323,116	323,116	329,893	329,893	0	0
(The following 5 lines are consolidated into "Wind & Solar Property" on the exhibit)										
Lake Winds	303,735	303,735	304,009	304,009	306,259	306,259	345,225	345,225	382,813	382,813
Cross Winds	265,519	265,519	269,662	269,662	358,885	358,885	543,833	543,833	454,389	454,389
Gratiot Wind	0	0	0	0	0	0	0	0	224,810	224,810
Crescent Wind	0	0	0	0	0	0	0	0	0	0
Solar Energy	20,000	16,529	60,169	15,681	97,962	15,131	103,419	19,483	121,983	25,760
(The following 2 lines are consolidated into the line "Miscellaneous" on the exhibit)										
Fidelity / Crime	54,463	26,915	54,463	26,832	57,104	28,074	59,488	29,065	54,000	25,785
Spare Transformer	32,145	32,145	37,479	37,479	41,226	41,226	51,004	51,004	74,805	74,805
Overhead Power Lines (T&D) [3]	2,206,425	2,206,425	3,227,243	3,227,243	3,452,873	3,452,873	0	0	0	0
Property	**9,366,911**	**8,430,396**	**10,674,480**	**9,726,079**	**12,179,666**	**10,920,489**	**8,279,236**	**7,073,307**	**9,098,866**	**7,772,263**
(The following 2 lines are consolidated into the line "General Liability" on the exhibit)										
General Liability (incl Profesional)	10,879,989	5,282,981	10,995,319	5,323,491	11,121,481	5,374,054	12,553,591	6,028,920	13,208,909	6,324,130
Railroad Protective Liability	0	0	3,500	1,750	3,500	1,750	3,500	1,750	3,500	1,750
Fiduciary Liability	609,089	301,006	536,280	264,203	474,791	228,850	474,791	227,425	484,791	236,117
(The following 5 lines are consolidated into the line "Work Comp" on the exhibit)										
Workers' Comp	1,115,441	557,721	1,306,217	653,109	1,753,000	876,500	2,014,575	1,007,288	2,115,318	1,057,659
Less WC to Capital	0	0	0	0	(767,483)	(358,491)	(979,569)	(452,112)	(1,105,000)	(500,879)
WC Self-Insured Bond	15,000	7,500	15,000	7,500	15,000	7,500	15,000	7,500	15,000	7,500
Workers' Comp (Multi-States)	2,180	1,090	2,392	1,196	2,625	1,313	2,979	1,490	3,312	1,656
Workers' Comp (Ohio)	0	0	0	0	223	112	129	65	126	63
D&O Liability	1,298,925	629,329	1,222,021	590,236	1,243,456	599,546	1,315,964	630,347	1,676,923	800,730
Cyber Liability	512,500	235,891	563,750	258,677	544,121	249,153	543,216	247,190	662,678	316,429
(The following 3 lines are consolidated into the line "Miscellaneous" on the exhibit)										
D&O Special [4]	0	0	0	0	31,125	14,629	0	0	0	0
Non-Owned Aircraft Liability	28,380	14,474	25,839	13,178	27,133	13,838	30,524	15,567	41,762	21,299
Nuclear Liability	88,064	88,064	98,684	98,684	98,684	98,684	98,684	98,684	98,684	98,684
Liability	**14,549,568**	**7,118,056**	**14,769,002**	**7,212,024**	**14,547,656**	**7,107,438**	**16,073,384**	**7,814,114**	**17,206,003**	**8,365,138**
Premium Total	**23,916,479**	**15,548,452**	**25,443,482**	**16,938,103**	**26,727,322**	**18,027,927**	**24,352,620**	**14,887,421**	**26,304,869**	**16,137,401**

Notes:
The amounts above for 2016-2020 are the invoiced amounts for the renewal that took place in that year.
Some 2016-2020 renewal invoice amounts were taken from spreadsheets that were available electronically and may not exactly match the invoice.
1 - In 2019 the property deductible was increased to $10 million from $1.7 million.
2 - In 2020 business interruption insurance coverage was not renewed.
3 - In 2019 the overhead power lines (T&D) insurance was not renewed.
4 - D&O Special is a 3-year policy period and premium is paid at the beginning of the period for all three years.

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No: U-20963**
Consumers Energy Company | **Exhibit: AG-1.55**
June 22, 2021
CECo Response to AG-CE-859

2021 Premiums for Electric Operations (with 2016 - 2020 invoice totals and calculations) AG-CE-859

Insurance	2019 O&M Insurance Expense Total	2020 O&M Insurance Expense Total	CE Elec Portion of 2020 Renewal	Months of Coverage in 2021	Premium Attributed to 2021 O&M Insurance Expense	Anticipated Changes In Operations or Insurance Coverage That Could Affect 2021 Insurance Renewal	Escalation Rate Applied to 2020 Renewal	CE Elec Portion of 2021 Renewal	Months of Coverage in 2021	Premium Attributed to 2021 O&M Insurance Expense	2021 O&M Insurance Expense Total
(The following 2 lines are consolidated into "Main Property" on the exhibit)											
Main Property (incl terrorism) [1]	5,121,869	6,031,176	6,583,901	8	4,389,267		1.25	8,229,876	4	2,743,292	7,132,559
Business interruption [2]	325,376	219,929	-		0						
(The following 5 lines are consolidated into "Wind & Solar Property" on the exhibit)											
Lake Winds	309,506	348,356	382,813	11	350,912		1.25	478,516	1	39,876	390,788
Cross Winds	374,297	536,380	454,389	11	416,523		1.25	567,986	1	47,332	463,855
Gratiot Wind	-	-	225,000	12	225,000	Add Gratiot Dec 2020	1.25	281,250	0	0	225,000
Crescent Wind	-	-	-	0	0	Add Crescent Feb 2021	0.00	225,000	12	225,000	225,000
Solar Energy	15,494	22,152	25,760	11	23,613		1.25	32,200	1	2,683	26,297
(The following 2 lines are consolidated into the line "Miscellaneous" on the exhibit)											
Fidelity / Crime	28,258	26,462	25,785	3	6,446		1.05	27,074	9	20,306	26,752
Spare Transformer	42,854	54,973	74,805	10	62,338		1.25	93,506	2	15,584	77,922
Overhead Power Lines (T&D) [3]	2,636,678	-	-								
Property	**8,854,332**	**7,239,428**	**7,772,453**		**5,474,100**			**9,935,409**		**3,094,074**	**8,568,174**
(The following 2 lines are consolidated into the line "General Liability" on the exhibit)											
General Liability (incl Profesional)	5,712,188	6,200,059	6,324,129	6	3,162,065		1.08	6,837,912	6	3,418,956	6,581,020
Railroad Protective Liability	1,752	1,750	1,750	6	875		1.05	1,838	6	919	1,794
Fiduciary Liability	232,701	234,044	236,117	6	118,059		1.05	247,923	6	123,961	242,020
(The following 5 lines are consolidated into the line "Work Comp" on the exhibit)											
Workers' Comp	942,995	1,032,619	1,057,659	6	528,830		1.07	1,132,387	6	566,194	1,095,023
Less WC to Capital	(452,112)	(500,879)	(500,879)					(525,607)			(525,607)
WC Self-Insured Bond	-	-	7,500	2	1,250		1.00	7,500	10	6,250	7,500
Workers' Comp (Multi-States)	-	-	3,312	10	2,760		1.04	3,444	2	574	3,334
Workers' Comp (Ohio)	-	-	68				1.04	71			68
D&O Liability	598,814	630,347	800,730	12	800,730		1.10	877,208	0	0	800,730
Cyber Liability	249,154	247,190	316,429	12	316,429		1.05	332,779	0	0	316,429
(The following 3 lines are consolidated into the line "Miscellaneous" on the exhibit)											
D&O Special [4]	4,872	4,872	4,876	3	1,219		1.45	7,070	9	5,303	6,522
Non-Owned Aircraft Liability	14,274	16,996	16,996	9	12,747		1.05	17,846	3	4,461	17,208
Nuclear Liability	98,684	98,684	98,684	0	0		1.00	98,684	12	98,684	98,684
Liability	**7,403,322**	**7,965,682**	**8,367,371**		**4,944,963**			**9,039,054**		**4,225,302**	**8,644,726**
Premium Total	**16,257,654**	**15,205,110**	**16,139,824**		**10,419,062**			**18,974,464**		**7,319,376**	**17,212,899**

Notes:
The amounts above for 2016-2020 are the invoiced amounts for the renewal that took place in that year.
Some 2016-2020 renewal invoice amounts were taken from spreadsheets that were available electronically and may not exactly match the invoice.
1 - In 2019 the property deductible was increased to $10 million from $1.7 million.
2 - In 2020 business interruption insurance coverage was not renewed.
3 - In 2019 the overhead power lines (T&D) insurance was not renewed.
4 - D&O Special is a 3-year policy period and premium is paid at the beginning of the period for all three years.

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY

Exhibit AG-1.56
Case No: U-20963
June 22, 2021

Calculation of Insurance Expense 2022 Test Year

Line #	(a)		Electric Insurance Expense (b)
1	**2020 Actual**		$ 15,715,197
2	Gratiot Wind Project - December 2020		225,000
3	Adjusted 2020 expense		15,940,197
4	2020 Inflation Cost Adjusted @ 2%		16,259,001
5	Crescent Wind Project - February 2021		225,000
5	Adjusted 2021 forecasted expense		16,484,001
7	2021 Inflation Cost Adjusted @ 2%		16,813,681
8	Hartland Wind Park December 2021		300,000
9	**2022 Forecasted Expense**		**17,113,681**
10	**Refunds and Distributions:**		
11	2020	(13,861,120)	
12	2019	(7,117,180)	
13	2018	(10,893,094)	
14	2017	(3,754,317)	
15	2016	(3,858,353)	
16	Average		(7,896,813)
17	**2022 Net Insurance Expense - AG**		**9,216,868**
18	2022 CECo Calculated Net Insurance Expense		13,800,000
19	**Excess/Disallowance**		**$ (4,583,132)**

Question:

52. In case U-20697, Mr. Tolonen on his Exhibit A-105 (JDT-2) projected IT Investments O & M to be $13.9 million for 2019 and $17.0 million for 2020. Now in this case his Exhibit A-107, page 1 shows that expense levels for the same category are $10.8 million (for 2019) and are expected to be $8.4 million (for 2020). On a percentage basis this represents reductions of 22% and 51% respectively for the two years. Please explain these significant changes over the short timeframe involved.

Response:

Historically IT Investments O&M actuals have been very close to, or over projected spend amounts as shown in attachment U20963-AG-CE-821--Tolonen_ATT1. The changes from projections in the referenced cases are anomalies due to unique business circumstances in 2019 and 2020. For example, in 2019, IT was able to (1) gain efficiencies by executing the Microsoft 365 and Windows 10 Upgrade projects together thereby reducing internal labor, contractor costs, and associated overheads by $1.2 million and, (2) negotiate better contractor costs than anticipated for the HR Support Pack and BSI Upgrade and Data Center 2.0 project for a $524,000 reduction. IT did not reach investments O&M projections in 2020 primarily due to the following circumstances: (1) the Summer Peak Use Rate (SPUR) – Release 2 project capitalized costs initially estimated as O&M, resulting in a $1.4 million O&M reduction; (2) the Oracle Server Database project started later than planned resulting in a $662,000 O&M reduction; (3) the HR – Union Contract Changes project was delayed due to the COVID-19 pandemic delaying finalization of the union contract, resulting in a $386,000 O&M reduction; and (4) application migration efficiencies identified in the Data Center 2.0 project resulting in a $1.1 million O&M reduction.

Jeffrey D Tolonen

Jeffrey D. Tolonen
May 25, 2021

U20963-AG-CE-891
Page **1** of **1**

Question:

8. Refer to Exhibit A-107 (JDT-5), page 1. Please:

a. Provide the same information in Excel for each year 2016-2018.
b. Explain what functions the Investment Planning area performs. Provide the number of employees and contractors in this area at each year end 2016 to 2022.
c. Explain what Investment O&M is for, what it includes, and how it differs from Operational O&M in Exhibit A-104.

Response:

a. Please refer to U20963-AG-CE-891-Tolonen_ATT1 for Investments O&M expense for each year 2016 – 2018.

b. Please refer to my direct testimony page 37, lines 22-24 and page 38, lines 1-16 where Investment Planning is described as an activity performed in the preliminary project stage to help the Company make investment decisions. Investment Planning activities are performed by different roles across the IT department rather than exclusively by a specific IT area. The Company cannot provide the number of employees and contractors that only perform Investment Planning since it is a portion of the labor across many IT employees and contractors.

c. Investments O&M is a portion of project expenditure that must adhere to the FASB ASC 350-40 guideline for all project activities that should be expensed rather than capitalized such as project planning, data conversion, and project hyper-care activities. Operations O&M is used to provide the required level of operational support, reliability, and security for existing IT assets. Some of these support activities and fees include software asset management, maintenance, existing vendor support agreements, cloud computing expenses, and security patches.

Jeffrey D. Tolonen

Jeffrey D. Tolonen
June 2, 2021

MICHIGAN PUBLIC SERVICE COMMISSION				Case No.:	U-20963
Consumers Energy Company				Exhibit No.:	AG-CE-891
Summary of Actual Information Technology Investments O&M Expenses				Page:	1 of 1
For the Years 2016 - 2018				Witness:	JDTolonen
($000)				Date:	May 2021

Line No.	Description (a)	(b) Actual 12 Mos Ended 12/31/2016*	(c) Actual 12 Mos Ended 12/31/2017	(d) Actual 12 Mos Ended 12/31/2018
1	**Investments Planning**	**$ 484**	**$ 499**	**$ 938**
2	Labor		373	431
3	Contracts		125	470
4	Business Expense		0	37
5	Material		0	0
6	**Investments O&M**	**$ 8,496**	**$ 14,890**	**$ 15,165**
7	Labor		3,067	2,659
8	Software		0	1,821
9	Material		275	844
10	Contractor Costs		11,385	8,722
11	Overhead & Others		162	1,119
12	**Total Investments Expense**	**$ 8,980**	**$ 15,388**	**$ 16,103**

U20963-AG-CE-893
Page **1** of **1**

Question:

10. Refer to Exhibit A-109 (JDT-8). Please provide the amount of cloud computing fees incurred by the Company each year 2016 to 2020 and forecasted for 2021 and 2022. Provide a reference to the O&M or capital expenditures exhibit and line number in which these costs are included and how much. If costs are deferred, what is the amortization period?

Response:

Assuming "incurred" means expensed, please refer to attachment U20963-AG-CE-893-Tolonen_ATT1 for cloud computing costs expensed as Operations O&M each year 2016 to 2020 and projected for 2021 and 2022, including reference to the O&M Exhibit and line number where these costs are included. For cloud computing costs that are prepaid, they are amortized over the life of the contract.

Jeffrey D. Tolonen
June 2, 2021

Information Technology

MICHIGAN PUBLIC SERVICE COMMISSION							Case No.:	U20963
Consumers Energy Company							Exhibit No.:	AG-CE-893
Cloud Computing Costs Expensed							Page:	1 of 1
For the Years 2016 - 2019 and Projected Years 2020 - 2022							Witness:	JDTolonen
Electric Allocation							Date:	May 2021
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Actual				**Projected**		
Line No.	**Cost**	**12 Months Ended 12/31/2016**	**12 Months Ended 12/31/2017**	**12 Months Ended 12/31/2018**	**12 Months Ended 12/31/2019**	**12 Months Ending 12/31/2020**	**12 Months Ending 12/31/2021**	**12 Months Ending 12/31/2022**
1	Cloud Computing Expense	$ -	$ 896,335	$ 1,163,291	$ 1,311,769	$ 2,089,147	$ 7,232,939	$ 7,796,319
2	Case No.	N/A	U20134	U20697	U20963	U20963	U20963	U20963
3	Exhibit Reference	N/A	A-83 (JRH-1) line 3, column b	A-104 (JDT-1) line 2, column b	A-104 (JDT-2) line 2, column b	A-104 (JDT-2) line 2, column c	A-104 (JDT-2) line 2, column d	A-104 (JDT-2) line 2, column e

Question:

35. Refer to page 25 of Ms. Conrad's direct testimony. Please:
a. Provide the actual percentage payout of target in each year 2010 to 2020 for the EICP with the officer and the non-officer plan payouts reported separately.
b. Provide the amount of incentive compensation that would be paid out to officers and non-officer employees if only the operating performance measures are achieved at target in 2022.
c. Provide the amount of incentive compensation that would be paid out to officers and non-officer employees if only the operating performance measures are achieved at threshold level in 2022.

Response:

a. Below is a table of the actual percentage payout of target in each year from 2010 to 2020 for officers and non-officers.

	Overall Short-term Incentive Payout										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Officer	143%	121%	105%	135%	124%	146%	141%	104%	136%	122%	153%
Non-Officer	100%	0%	115%	118%	125%	123%	133%	112%	123%	111%	139%

b. The amount of incentive compensation that would be paid out to officers and non-officer employees if only the operating performance measures are achieved at target in 2022 would be:

Officers $0

Non-Officers $1,966,600

c. The amount of incentive compensation that would be paid out to officers and non-officer employees if only the operating performance measures are achieved at threshold in 2022 would be:

Officers $0

Non-Officers $983,300

Amy M. Conrad
June 4, 2021

U20963-AG-CE-794
Page **1** of **1**

Question:

25. Provide a schedule showing the Employee Benefit Plan elements and related costs that make up the line "Other Benefits" for each year as shown on Exhibit A-62 (LBC-1).

Response:

Other Benefits includes the Company's Educational Assistance, Absence Management, Benefits Consulting, Benefits Department Labor and Benefits Non-Labor.

Description	**12 mos. ended 12/31/2019**	**12 mos. ended 12/31/2020**	**12 mos. ended 12/31/2021**	**12 mos. ended 12/31/2022**
Other Benefits				
Educational Assistance	285	428	428	428
Absence Management	727	741	661	661
Consulting	398	616	428	428
Benefits Department Labor	0	1,129	1,140	1,140
Benefits Non-Labor	285	(576)	328	328
Total Expense	**$1,695**	**$2,337**	**$2,984**	**$2,984**

Lora Christopher

LORA B. CHRISTOPHER
May 20, 2021

U20963-AG-CE-980
Page **1** of **1**

Question:

43. Refer to Exhibit A-62 (LBC-1), page 1. Please:
a. Provide the same information for 2020 actual.
b. Provide the basis and calculations in Excel showing how the Company determined the amounts for 2020 through 2021 for lines 2, 3, 4, and 6.

Response:

- **a.** Actual numbers for 2020 are noted in the Exhibit A-62 (LBC-1) page 1 as column "c", 12 months ended December 31, 2020.
- **b.** The basis and calculations for projected expenses on lines 2,3,4, and 6 are detailed in Confidential Exhibit A-62 (LBC-1) and witness Christopher's workpapers, which were provided to all parties to this case.

Lora Christopher

LORA B. CHRISTOPHER
May 27, 2021

PAGES 3-18 CONSISTS OF 16 PAGES OF WORKPAPERS OF LORA CRISTOPHER

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20963
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

WORKPAPERS

OF

LORA B. CHRISTOPHER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2021

Exhibit: AG-1.60

RETIREMENT BENEFITS
Pension

Case No. U-20963
WP-LBC-1
(Exh A-62 (LBC-1), Line 1)

Consumers Energy Company
($000)

Line No.	Department	Historical 12 mos. ended 12/31/2019	12 mos. ended 12/31/2020	Projected 12 mos. ended 12/31/2021	12 mos. ended 12/31/2022	Variance Explanation
	(a)					(f)
1	**Pension Plans**	**$ 5,546**	**$ 4,540**	**$ (3,426)**	**$ (8,902)**	Elec/Gas Cost Split - 2020 - 2022: 59% Elec; 41% Gas Elec Capital Expense mid 2020 - 2022: 49% Assumption Changes Discount rate - 2019 - 4.48%/4.32% 2020 - 3.37%/3.17% 2021 - 2.73%/2.41% 2022 - 2.71%/2.39% Expected Return on Assets - 2019 - 7.00% 2020 - 6.75% 2021 - 6.75% 2022 - 6.50%

RETIREMENT BENEFITS
Pension

Case No. U-20963
WP-LBC-2
(Exh A-62 (LBC-1), Line 1)

Consumers Energy Company
($000)

Line No.	Department	Historical 12 mos. ended 12/31/2019	12 mos. ended 12/31/2020	Projected 12 mos. ended 12/31/2021	12 mos. ended 12/31/2022	Allocation Methodology
	(a)					(f)
	Pension Plans					
1	Total	$ 17,248	$ 31,400	$ 20,500	$ 10,700	Labor
2	Elec Portion	$ 17,542	$ 18,526	$ 12,095	$ 6,313	
3	Elec Portion O&M	**$ 5,546**	**$ 4,540**	**$ (3,426)**	**$ (8,902)**	

Exhibit: AG-1.60

Exhibit: AG-1.60

RETIREMENT BENEFITS
Defined Company Contribution Plan

Case No. U-20963
WP-LBC-3
(Exh A-62 (LBC-1), Line 2)

Consumers Energy Company
($000)

Line No.	Department	Historical 12 mos. ended 12/31/2019	Projected 12 mos. ended 12/31/2020	Projected 12 mos. ended 12/31/2021	Projected 12 mos. ended 12/31/2022	Variance Explanation
	(a)					(f)
1	**Defined Company Contribution Plan**	**$ 8,567**	**$ 9,674**	**$ 10,564**	**$ 12,128**	Elec/Gas Cost Split - 2020 - 2022: 59% Elec; 41% Gas Elec Capital Expense mid 2020 - 2022: 49%

RETIREMENT BENEFITS
Defined Company Contribution Plan ($000)

Case No. U-20963
WP-LBC-4
(Exh A-62 (LBC-1), Line 2)

Consumers Energy Company
($000)

		Historical	Projected			
Line No.	**Department**	**12 mos. ended 12/31/2019**	**12 mos. ended 12/31/2020**	**12 mos. ended 12/31/2021**	**12 mos. ended 12/31/2022**	**Allocation Methodology**
	(a)					(f)
	Defined Company Contribution Plan					
1	Total	$ 28,150	$ 31,785	$ 35,108	$ 40,304	Labor
2	Elec Portion	$ 16,475	$ 18,753	$ 20,714	$ 23,780	
3	Elec Portion O&M	**$ 8,567**	**$ 9,674**	**$ 10,564**	**$ 12,128**	

RETIREMENT BENEFITS
401(k) Employees' Savings Plan ($000)

Case No. U-20963
WP-LBC-5
(Exh A-62 (LBC-1), Line 3)

Consumers Energy Company
($000)

Line No.	Department	Historical	Projected			Variance Explanation
		12 mos. ended 12/31/2019	12 mos. ended 12/31/2020	12 mos. ended 12/31/2021	12 mos. ended 12/31/2022	
	(a)					(f)
1	**401 (k) Employees' Savings Plan**	**$ 8,273**	**$ 8,632**	**$ 10,963**	**$ 11,573**	Elec/Gas Cost Split - 2020 - 2022: 59% Elec; 41% Gas Elec Capital Expense mid 2020 - 2022: 49%

Case No. U-20963
WP-LBC-6
(Exh A-62 (LBC-1), Line 3)

RETIREMENT BENEFITS
401(k) Employees' Savings Plan ($000)

Consumers Energy Company
($000)

Line No.	Department	Historical 12 mos. ended 12/31/2019	12 mos. ended 12/31/2020	Projected 12 mos. ended 12/31/2021	12 mos. ended 12/31/2022	Allocation Methodology
	(a)					(f)
	401 (k) Employees' Savings Plan					
1	Total	$ 27,113	$ 28,264	$ 36,326	$ 38,354	Labor
2	Elec Portion	$ 15,808	$ 16,614	$ 21,367	$ 22,563	
3	Elec Portion O&M	**$ 8,273**	**$ 8,632**	**$ 10,963**	**$ 11,573**	

HEALTH CARE BENEFITS
Active Health Care ($000)

Case No. U-20963
WP-LBC-7
(Exh A-62 (LBC-1), Line 4)

Consumers Energy Company
($000)

Line No.	Department	Historical 12 mos. ended 12/31/2019	12 mos. ended 12/31/2020	Projected 12 mos. ended 12/31/2021	12 mos. ended 12/31/2022	Variance Explanation
	(a)					(f)
1	**Active Health Care/Life Insur./LTD**	**$ 25,353**	**$ 25,822**	**$ 22,640**	**$ 23,856**	Elec/Gas Cost Split - 2020 - 2022: 56% Elec; 44% Gas Elec Capital Expense mid 2020 - 2022: 49% Health costs increase 4.5% in 2020 & 5.6% in 2021 and 2022 based on rate studies Life insurance/LTD costs increase 3.5% annually from 2020 to 2022

HEALTH CARE BENEFITS
Active Health Care ($000)

Consumers Energy Company
($000)

Case No. U-20963
WP-LBC-8
(Exh A-62 (LBC-1), Line 4)

Line No.	Department	Historical 12 mos. ended 12/31/2019	Projected 12 mos. ended 12/31/2020	Projected 12 mos. ended 12/31/2021	Projected 12 mos. ended 12/31/2022	Allocation Methodology
	(a)					(f)
	Active Health Care/Life Insur./LTD					
1	Total	$ 84,549	$ 88,410	$ 78,267	$ 82,523	Headcount
2	Elec Portion	$ 47,584	$ 48,923	$ 43,243	$ 45,627	
3	Elec Portion O&M	**$ 25,353**	**$ 25,822**	**$ 22,640**	**$ 23,856**	

HEALTH CARE BENEFITS
Retiree Health Care ($000)

Consumers Energy Company
($000)

Case No. U-20963
WP-LBC-9
(Exh A-62 (LBC-1), Line 5)

Line No.	Department	Historical 12 mos. ended 12/31/2019	Projected 12 mos. ended 12/31/2020	Projected 12 mos. ended 12/31/2021	Projected 12 mos. ended 12/31/2022	Variance Explanation
	(a)					(f)
1	**Retiree Health Care/Life Insurance**	**$ (40,032)**	**$ (52,085)**	**$ (63,291)**	**$ (63,301)**	Elec/Gas Cost Split - 2020 - 2022: 56% Elec; 44% Gas Elec Capital Expense mid 2020 - 2022: 49% Assumption Changes Discount rate - 2019 - 4.42% 2020 - 3.32% 2021 - 2.69% 2022 - 2.69% Expected Return on Assets - 2019 - 7.00%

HEALTH CARE BENEFITS
Retiree Health Care ($000)

Case No. U-20963
WP-LBC-10
(Exh A-62 (LBC-1), Line 5)

Consumers Energy Company
($000)

Line No.	Department	Historical 12 mos. ended 12/31/2019	Projected 12 mos. ended 12/31/2020	12 mos. ended 12/31/2021	12 mos. ended 12/31/2022	Allocation Methodology
	(a)					(f)
	Retiree Health Care/Life Insurance					
1	Total	$ (63,885)	$ (85,770)	$ (104,870)	$ (105,070)	Headcount
2	Elec Portion	$ (36,421)	$ (48,031)	$ (58,727)	$ (58,839)	
3	Elec Portion O&M / Other	**$ (40,032)**	**$ (52,085)**	**$ (63,291)**	**$ (63,301)**	

Exhibit: AG-1.60

OTHER BENEFITS
Educational Assistance, Absence Management and Labor ($000)

Case No. U-20963
WP-LBC-11
(Exh A-62 (LBC-1), Line 6)

Consumers Energy Company
($000)

Line No.	Department	Historical 12 mos. ended 12/31/2019	Projected 12 mos. ended 12/31/2020	12 mos. ended 12/31/2021	12 mos. ended 12/31/2022	Variance Explanation
	(a)					(f)
1	**Other**	**$ 1,695**	**$ 2,337**	**$ 2,984**	**$ 2,984**	Elec/Gas Cost Split - 2020 - 2022: 56% Elec; 44% Gas

Exhibit: AG-1.60

Case No. U-20963
WP-LBC-12
(Exh A-62 (LBC-1), Line 6)

OTHER BENEFITS
Educational Assistance, Absence Management and Labor ($000)

Consumers Energy Company
($000)

Line No.	Department	Historical 12 mos. ended 12/31/2019	12 mos. ended 12/31/2020	Projected 12 mos. ended 12/31/2021	12 mos. ended 12/31/2022	Allocation Methodology
	(a)					(f)
	Other*					
1	Total	$ 5,056	$ 4,100	$ 5,235	$ 5,235	Headcount
2	Elec Portion	$ 1,695	$ 2,337	$ 2,984	$ 2,984	
3	Elec Portion O&M / Other	**$ 1,695**	**$ 2,337**	**$ 2,984**	**$ 2,984**	

* Educational Assistance / Absence Management / Other Expenses

RETIREMENT BENEFITS
Pension, DCCP, 401(k) Savings

Case No. U-20963
WP-LBC-13
(Exh A-62 (LBC-1), lines 1, 2 & 3)
(Exh A-63 (LBC-2)

Consumers Energy Company
($000)

	12 Months Ending Dec 31, 2022	Capital	12 Months Ending Dec 31, 2022
12 Months Ending December 31, 2021 - Consumers Energy Pension Plans ($000)			
Total			
Service Cost	$ 52,900		
Other Expense	(41,928)		
Actuarial Services/PBGC Premiums	1,100		
	12,072		
Elec Portion (59% - Labor basis)			
Service Cost	$30,401		
Other Expense	(24,737)		
Actuarial Services/PBGC Premiums	649		
Elec Capital Portion (49%)			
Service Cost		14,896	
Actuarial Services/PBGC Premiums		318	
Total Consumers Energy Pension O&M - Elec			**$ 15,836**
Total Consumers Energy Pension Other Expense - Elec			**$ (24,737)**
			$ (8,902)
12 Months Ending Decemer 31, 2021 - Consumers Energy DCCP ($000)	$ 40,304		
Elec Portion (59% - Labor basis)	23,780		
Elec Capital Portion (49%)		11,652	
Total Consumers Energy DCCP O&M - Elec			**$ 12,128**
12 Months Ending December 31, 2021 - Consumers Energy Employees' 401k - Savings Plan Match ($000)			
401k - Savings Plan Match	$ 38,243		
Elec Portion (59% - Labor basis)	22,563		
Elec Capital Portion (49%)		11,056	
Elec Portion Fees		66	
Total Consumers Energy Savings Plan Match O&M - Elec			**$ 11,573**

HEALTH CARE BENEFITS
Active Health Care/Life Insurance/LTD ($000)

Case No. U-20963
WP-LBC-14
(Exh A-62 (LBC-1), Line 4)

Consumers Energy Company
($000)

Employee Health Care & Non-Health Care Cost Increases - 2019 and 12 Months Ending December 2022

Employee Health/Non-Health Costs	2019 Actual	12 Months Ending December 2022	Assumptions
Employee Health Care	$80,671	$78,147	Health costs increase 4.5% in 2020 and 5.6% in 2021/2022
Employee Non-Health Care (Life/LTD) Total	$2,809	$3,329	Life/LTD costs increase 3.5% annually from 2019 to 2022
Total Employee Health/NonHC Expense	**$83,480**	**$81,476**	
Fidelity Fees	1,069	1,047	
	84,549	**82,523**	
Electric Total (57%/56%)	**$47,584**	**$45,627**	
Electric Capital (48%/49%)	22,840	22,357	
Fidelity Fees	609	586	
Electric O&M	**25,353**	**23,856**	
Gas Total (43%/44%)	**$35,896**	**$35,849**	
Gas Capital (58%/59%)	20,102	21,151	
Fidelity Fees	460	461	
Gas O&M	**16,254**	**15,159**	

Retiree Health Care/Life Insurance

Consumers Energy Company

Case No. U-20963
WP-LBC-15
(Exh A-62 (LBC-1), line 5)
(Exh A-64 (LBC-3)

CONSUMERS ENERGY RETIREE OPEB EXPENSE (ASC 715) - Projected 12 Months Ending December 31, 2022

AON Hewitt* OPEB - Projected 12-months ending December 31, 2022	**($105,070,000)**
OPEB Service Cost	**$16,259,000**
OPEB Other Expense	**($121,559,000)**

RETIREE HEALTH CARE & LIFE INSURANCE - TOTAL

	TOTAL EXPENSE	CAPITAL EXPENSE	O & M EXPENSE
CONSUMERS ENERGY (Elec = 56%; Gas = 44% of Total) (Capital - 49% Elec; 59% Gas)			
Service Cost	$16,259,000	($8,682,000)	$7,577,000
Other Expense	($121,559,000)		($121,559,000)
Actuarial Service / Fees	$230,000		$230,000
TOTAL Consumers Energy 2022 OPEB Expense	($105,070,000)	($8,682,000)	($113,752,000)

CONSUMERS ENERGY ELECTRIC RETIREE OPEB EXPENSE (ASC 715) - Projected 12 months ending December 31, 2022

RETIREE HEALTH CARE & LIFE INSURANCE - ELECTRIC

	TOTAL EXPENSE	CAPITAL EXPENSE	O & M EXPENSE
CONSUMERS ENERGY (Elec = 56% of Total with 49% Capital)			
Service Cost	$9,105,000	($4,461,450)	$4,643,550
Other Expense	($68,073,000)		($68,073,000)
Actuarial Service / Fees	$129,000		$129,000
TOTAL Consumers Energy 2022 Elec OPEB Expense	**($58,839,000)**	($4,461,450)	**($63,300,450)**

*Hewitt - estimate

Question:

44. Refer to exhibit A-63 (LBC-2), pages 1 and 2. Please:
a. Expand the two schedules to include the same information for each year 2016 to 2019.
b. For page 1, please:
i. Explain what the basis is for the continuing decline in the discount rate and the expected return rate from 2020 to 2028.
ii. Provide the basis for the 3.70% annual salary increase.
iii. Provide the impact on pension expense for 2022 if the discount rate, expected return and salary increase rate remained at the same rate as in 2020.
c. For page 2, please:
i. Explain what the basis is for the continuing decline in the discount rate and the expected return rate from 2020 to 2028.
ii. Provide the impact on pension expense for 2022 if the discount rate, expected return rate, and salary increase rate remained at the same rate as in 2020.

Response:

a. See attached file: U-20963.AG.CE.981.Part.A – The schedules are provided by our third party actuary; AON Hewitt. The file was provided on February 6, 2017 and has 2016 – 2019 as requested and is based on the assumptions at that time.
b. i. The basis for continuing decline in the discount rate and the expected return rate from 2020 – 2028 is outlined in Confidential Exhibit A-65 (LBC-4).
ii. Salary increase of 3.7% was used by AON Hewitt in its assumptions. These are third party assumptions, not Consumers Energy's.
iii. Consumers Energy has not performed these calculations and has not determined the impact.

c. i. The basis for continuing decline in the discount rate and the expected return rate from 2020 – 2028 is outlined in Confidential Exhibit A-65 (LBC-4), page 2.
ii. Consumers Energy has not performed these calculations and has not determined the impact.

Lora Christopher

LORA B. CHRISTOPHER
June 1, 2021

U20963-AG-CE-982
Page **1** of **1**

Question:

45. Refer to exhibit A-64 (LBC-3). Please:
a. Expand the schedule to include the same information for each year 2016 to 2018.
b. Explain what the basis is for the continuing decline in the APBO discount rate, interest rates, and the expected return rate from 2019 to 2028.
c. Provide the impact on OPEB expense for 2022 if the discount rate, interest rates, and expected return rates remained at the same rate as in 2020.

Response:

a. See attached file: U20963-AG-CE-982-Christopher_ATT_1. The schedules are provided by our third party actuary; AON Hewitt. The file was provided on September 17, 2018 and has 2016 – 2018 as requested and is based on the assumptions at that time.

b. These projections were provided in September 2018, and all rates shown for 2019 through 2028 were projected rates determined at that time, whereas rates shown for 2016 to 2018 are actual rates used for ASC 715 accounting purposes. The APBO discount rate, service cost effective interest rate, and the interest cost effective interest rate are assumed to remain level from 2019 to 2028. These rates declined from 2016 to 2018 and then were projected to increase from 2018 to 2019, as calculated by Consumers Energy's actuary and reflecting changes in high quality corporate bond rates as required under ASC 715 accounting. The expected rate of return on assets is determined each year by Consumers Energy with the assistance of their investment advisors. This assumption reflects plan asset allocation and expected capital market assumptions determined at each measurement date. The expected rate of return on assets assumption from 2019 to 2028 was determined by Consumers Energy and reflects their forward-looking view of potential changes in asset allocation and/or capital market assumptions.

c. These impacts have not been calculated.

Lora Christopher

LORA B. CHRISTOPHER
June 2, 2021

CMS Energy

Prepared on February 6, 2017

ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

	2015	2016	2017	2018	2019	2020	2021	2022
Funding Target	$ 1,615.7	$ 1,678.3	$ 1,772.7	$ 1,885.8	$ 1,949.8	$ 2,005.2	$ 2,130.7	$ 2,262.6
Value of Plan Assets	$ 1,943.3	$ 2,119.9	$ 2,138.5	$ 2,081.6	$ 2,070.1	$ 2,044.1	$ 2,009.4	$ 1,963.5
Credit Balance	$ 324.9	$ 495.6	$ 563.7	$ 509.6	$ 414.0	$ 303.2	$ 179.2	$ 21.8
Funded %	100.2%	96.8%	88.8%	83.4%	84.9%	86.8%	85.9%	85.8%
Effective Interest Rate	6.23%	6.04%	5.88%	5.71%	5.55%	5.41%	4.99%	4.59%
Contribution by Plan Year								
Utility	$ 209.5	$ 93.3	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 144.6
Nonutility	15.5	6.7	0.0	0.0	0.0	0.0	0.0	10.4
Total	$ 225.0	$ 100.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 155.0
At-Risk?	No	No	No	No	No	No	No	No
Benefit Restrictions?	No	No	No	No	No	No	No	No
Participant Count	12,715	12,410	12,118	11,922	11,718	11,495	11,260	11,007
PBGC Liability	$ 1,968.8	$ 2,007.7	$ 2,131.1	$ 2,227.7	$ 2,231.9	$ 2,245.1	$ 2,267.8	$ 2,292.3
Market Value of Assets	$ 1,978.7	$ 2,012.4	$ 2,101.2	$ 2,100.9	$ 2,085.0	$ 2,060.8	$ 2,025.6	$ 1,984.7
PBGC Flat Rate Premium	$ 0.7	$ 0.8	$ 0.8	$ 0.9	$ 0.9	$ 0.9	$ 0.9	$ 0.9
PBGC Variable Rate Premium	0.0	0.0	1.0	4.9	6.3	6.3	6.3	6.3
Total PBGC Premium	$ 0.7	$ 0.8	$ 1.8	$ 5.8	$ 7.2	$ 7.2	$ 7.2	$ 7.2
Projected Benefit Obligation	$ 2,546.7	$ 2,403.1	$ 2,562.3	$ 2,669.9	$ 2,699.4	$ 2,723.3	$ 2,741.8	$ 2,755.5
Market Value of Assets	1,979.0	2,013.1	2,101.2	2,100.9	2,085.0	2,060.8	2,025.6	1,984.7
Funded Status	$ 567.7	$ 390.0	$ 461.1	$ 569.0	$ 614.4	$ 662.5	$ 716.2	$ 770.8
ASC 715 Funded %	77.7%	83.8%	82.0%	78.7%	77.2%	75.7%	73.9%	72.0%
ASC 715 Accounting Expense								
Utility	$ 101.6	$ 51.9	$ 63.1	$ 75.4	$ 79.3	$ 89.1	$ 88.0	$ 89.2
Nonutility	2.8	1.5	1.7	2.1	2.2	2.4	2.4	2.5
Total	$ 104.4	$ 53.4	$ 64.8	$ 77.5	$ 81.5	$ 91.5	$ 90.4	$ 91.7
Components of Total Expense								
Service Cost	$ 49.0	$ 41.9	$ 44.6	$ 41.9	$ 41.4	$ 40.2	$ 38.7	$ 36.8
Interest Cost	101.7	85.3	88.6	92.0	92.7	93.3	93.6	93.8
Expected Return on Assets	(137.9)	(147.3)	(152.9)	(146.0)	(142.6)	(133.5)	(130.9)	(125.7)
Amortization of Outstanding Components	91.6	73.5	84.5	89.6	90.0	91.5	89.0	86.8
Total Expense	$ 104.4	$ 53.4	$ 64.8	$ 77.5	$ 81.5	$ 91.5	$ 90.4	$ 91.7
Assumptions								
Discount Rate	4.10%	4.52%	4.30%	4.29%	4.28%	4.27%	4.26%	4.25%
Expected Return on Assets	7.50%	7.25%	7.25%	7.00%	7.00%	6.75%	6.75%	6.50%
Salary Increases	3.00%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%

Projections reflect the following:

-January 1, 2016 census data
-PBO effective discount rate of 4.30% for pension and 4.16% for SERP in fiscal 2017, based on the December 31, 2016 yield curve
-November 2016 lump sum interest rates with an assumption that rates will increase by 50 basis points in 10 years
-Service Cost effective interest rate of 4.53% for pension and 4.19% for SERP in fiscal 2017, based on the December 31, 2016 yield curve
-Interest Cost effective interest rate of 3.56% for pension and 3.51% for SERP in fiscal 2017, based on the December 31, 2016 yield curve
-MP-2016 mortality improvement scale from 2006 for accounting purposes applies beginning December 31, 2016
-RP2014 mortality with MP-2016 mortality improvement scale for funding, PBGC, and lump sum purposes applies beginning January 1, 2018
-December 31, 2016 market assets provided by CMS for disclosure purposes.
-Expected and actual asset returns decrease 25 basis points every other year, starting with a drop to 7.00% in 2018
-Other provisions, assumptions and methods are the same as those used for December 31, 2016 ASC 715 disclosures.

CMS Energy

Prepared on September 17, 2018

ASC 715 OPEB Expense Estimates ($ millions)

	2016	2017	2018	2019	2020	2021	2022	2023
Funded Status, January 1								
Accumulated Postretirement Benefit Obligation	$ (1,227)	$ (1,409)	$ (1,095)	$ (1,052)	$ (1,053)	$ (1,051)	$ (1,046)	$ (1,039)
Plan Assets at Fair Value	1,208	1,264	1,420	1,411	1,449	1,485	1,520	1,553
Funded Status	$ (19)	$ (145)	$ 325	$ 359	$ 396	$ 434	$ 474	$ 514
ASC 715 Accounting Expense								
Utility	$ (36)	$ (28)	$ (90)	$ (85)	$ (79)	$ (79)	$ (79)	$ (73)
Nonutility	(5)	(5)	(6)	(6)	(5)	(6)	(6)	(5)
Total	$ (41)	$ (33)	$ (96)	$ (91)	$ (84)	$ (85)	$ (85)	$ (78)
Components of Total Expense								
Service Cost	$ 18	$ 19	$ 17	$ 15	$ 14	$ 14	$ 14	$ 13
Interest Cost	47	49	36	41	41	41	41	40
Expected Return on Assets	(86)	(90)	(97)	(97)	(95)	(98)	(97)	(98)
Amortization of Net (Gain) or Loss	21	29	15	13	12	11	10	9
Amortization of Prior Service Cost	(41)	(40)	(67)	(63)	(56)	(53)	(53)	(42)
Total Expense	$ (41)	$ (33)	$ (96)	$ (91)	$ (84)	$ (85)	$ (85)	$ (78)
Assumptions								
APBO Discount Rate	4.70%	4.49%/3.86%	3.74%	4.33%	4.33%	4.33%	4.33%	4.33%
Service Cost Effective Interest Rate	4.75%	4.89%/4.09%	3.93%	4.47%	4.47%	4.47%	4.47%	4.47%
Interest Cost Effective Interest Rate	3.89%	3.79%/3.33%	3.35%	4.01%	4.01%	4.01%	4.01%	4.01%
Expected Return on Assets	7.25%	7.25%/7.00%	7.00%	7.00%	6.75%	6.75%	6.50%	6.50%
Trend Rate—Initial Pre-65	7.25%	7.00%	7.50%	7.25%	7.00%	6.75%	6.50%	6.25%
Trend Rate—Initial Post-65	8.00%	7.75%	8.00%	7.75%	7.25%	7.00%	6.75%	6.50%
Trend Rate—Ultimate	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
Trend Rate—Ultimate Year Pre-65	2027	2027	2027	2027	2027	2027	2027	2027
Trend Rate—Ultimate Year Post-65	2027	2027	2027	2027	2027	2027	2027	2027
Expected Contribution	$ 0	$ 0	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4

2018-2023 expense projections reflect the following:

-January 1, 2017 census data.
-APBO discount rate of 4.33% in fiscal 2019+, based on June 30, 2018 yield curve.
-Service Cost effective interest rate of 4.47% in fiscal 2019+, based on June 30, 2018 yield curve.
-Interest Cost effective interest rate of 4.01% in fiscal 2019+, based on June 30, 2018 yield curve.
-June 30, 2018 market assets provided by CMS, projected to December 31, 2018, for fiscal 2019 expense.
-Projected contributions provided by CMS:
  -$0.4 million in all future years.
-Plan change providing improved survivor benefits for certain retirees effective as of December 31, 2018.
-Other provisions, assumptions and methods are the same as those used for December 31, 2017 ASC 715 disclosures.

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Question:

19. Explain on what basis the Company expects to reduce its expected return on pension assets from 6.75% to 6.50% for the projected test year and to even lower levels thereafter. Provide any study, analysis, or documents supporting this conclusion.

Response:

The expected return on plan assets is set each year by the Company. The Company uses future expected capital market assumptions, asset allocation information, and other resources provided by its consultants, which may include survey data and analysis of the Plan's asset allocation. The expected return assumption is based on long-term expectations and not short-term returns. The Company uses all this information to establish an expected return on plan assets assumption that best estimates its expectation. While this assumption is reviewed for each plan measurement, it may or may not be updated annually depending on the information that is presented.

The discount rate is set each year by the Company using its actuary's discount rate setting model. The model uses current high-quality bonds to match the Plan's cash flows using statistical techniques that create a yield curve that determines the effective discount rate for all maturities of pension payments. The model itself does not change annually, but the discount rate typically will be updated based on most current market

Actuary for the Company is Aon and detail has been provided as Part III Attachment #77 under plan tab and assumptions tab.

Lora Christopher

LORA B. CHRISTOPHER
May 20, 2021

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Question:

22. Provide a schedule showing actual asset return percentages for the Company's pension and OPEB assets (separately) for each of the years 2010 to 2020.

Response:

Pension	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Pension	13.6%	20.9%	-6.7%	17.7%	8.0%	-2.0%	7.4%	12.5%	14.1%	4.0%	13.0%	21.0%

OPEB	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Pension	13.6%	20.9%	-6.7%	17.7%	8.0%	-2.0%	7.4%	12.5%	14.1%	4.0%	13.0%	21.0%
Union Health VEBA	11.8%	21.7%	-6.7%	17.1%	9.3%	-2.2%	5.8%	15.4%	11.3%	2.0%	10.3%	16.9%
Non-Union Health VEBA	13.1%	23.0%	-6.4%	16.0%	8.7%	-1.6%	6.0%	15.0%	12.8%	4.0%	12.8%	20.0%
Union Life VEBA	14.0%	18.5%	-3.3%	12.7%	12.3%	-7.8%	1.2%	0.8%	2.7%	0.0%	0.0%	0.0%
Non-Union Life VEBA	14.0%	18.7%	-3.6%	13.6%	12.8%	-8.3%	0.9%	-0.1%	2.5%	0.0%	0.0%	0.0%

Lora Christopher

LORA B. CHRISTOPHER
May 21, 2021

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY

Exhibit AG-1.63
Case No: U-20963
June 22, 2021

Computation of Revenue Deficiency for Projected Test Year Ending December 2022
($000)

Line	Description	Company Filed Amount	AG Recommended Adjustments	Revised Amount
	(a)	(b)	(c)	(d)
1	Rate Base [(1)]	$ 12,905,858	$ (487,916)	$12,417,943
2	Rate of Return	5.95%	-0.53%	5.42%
3	Income Required	$ 767,619	$ (94,567)	$ 673,052
4	Adjusted Net Operating Income [(2)]	599,515	96,461	695,976
5	Income Deficiency (Sufficiency)	$ 168,104	$ (191,027)	$ (22,923)
6	Revenue Multiplier	1.3391	1.3391	1.3391
7	**Revenue Deficiency (Sufficiency)**	**$ 225,102**	**$ (255,798)**	**$ (30,696)**

[(1)] Rate Base Adjustments Exhibit AG-1.32.

[(2)] AG adjustments to Operating Income

			Source
Revenue		$ -	
Lower Forecast of O&M Expenses		101,062	Exhibit AG-1.46
Depreciation Expense		30,494	Exhibit AG-1.32
Total		$ 131,556	
Effective Tax Rate (1-1/1.3391)	25.32%		
Taxes		33,311	
Interest Synchronization for cap. Ex. adjustments		(1,784)	AG-1.63 WP1
Adjusted Net Operating Income		$ 96,461	

APPENDIX 1
COMPREHENSIVE LIST OF EXHIBITS

U-20963 Attorney General's Comprehensive List of Exhibits

<u>Exhibits for Witness Sebastian Coppola:</u>

Exhibit AG-1.1 DR Response – Adjusted Capital Contingency costs

Exhibit AG-1.2 DR Response – Distribution Capital Ex 2015-2022 & 2020 Actual

Exhibit AG-1.3 DR Response – Center Suspended Streetlights Cost and Units

Exhibit AG-1.4 DR Response – Streetlight Outage Restoration Tracker App

Exhibit AG-1.5 DR Response – LVD Asset Relocation Costs 2017-2021

Exhibit AG-1.6 DR Response – Grid Modernization Costs 2017-2021

Exhibit AG-1.7 DR Response – LVD Substation Reliability Costs 2020 and 2021

Exhibit AG-1.8 DR Response – System Control Projects 2021

Exhibit AG-1.9 DR Response - Power Generation Projects Not Approved

Exhibit AG-1.10 DR Response –Hydro Units No Cost/Benefit Analysis

Exhibit AG-1.11 DR Response – Excess Overhead Allocation

Exhibit AG-1.12 DR Response – Actual 2020 Capital Expenditures

Exhibit AG-1.13 DR Response – Customer Service Centers Timeline & Occupancy

Exhibit AG-1.14 DR Response – Marshall Training Center

Exhibit AG-1.15 DR Response – UCC Project

Exhibit AG-1.16 DR Response – Return to Work Project.

Exhibit AG-1.17 DR Response – Facilities 2020 Actual Capital Expenditures

Exhibit AG-1.18 Transportation Equipment Capital Expenditures 2020-2011 WP

Exhibit AG-1.19 DR Response – Workforce Expansion Transportation Equip.

Exhibit AG-1.20 DR Response – Telematics Selection and Cost Savings

Exhibit AG-1.21 DR Response – Telematics Installation & Benefits Status

Exhibit AG-1.22 DR Response – CRM IT Project

Exhibit AG-1.23 DR Response – C&I Account Management System IT Project

Exhibit AG-1.24 DR Response – Bill Design & Delivery IT Project

Exhibit AG-1.25 DR Response – Customer Self-Service Mobile App IT Project

Exhibit AG-1.26 DR Response – Customer Loyalty & Alternative Payment Pilot

Exhibit AG-1.27 DR Response – IT Devices Replacement

Exhibit AG-1.28 DR Response – Digital-Hybrid Cloud and Data Center Transform

Exhibit AG-1.29 DR Response – Core HR IT Project

Exhibit AG-1.30 DR Response – Integrated Business Planning and Reporting

Exhibit AG-1.31 DR Response – IT 2020 Actual Capital Expenditures

Exhibit AG-1.32 Summary Cap Ex, Rate Base and Depreciation Expense

Exhibit AG-1.33 Overall Cost of Capital

Exhibit AG-1.34 Cost of Common Equity

Exhibit AG-1.35 Cost of Common Equity-DCF

Exhibit AG-1.36 Cost of Common Equity-CAPM

Exhibit AG-1.37 Cost of Common Equity-Risk Premium

Exhibit AG-1.38 Market to Book Ratios

Exhibit AG-1.39 ROE Decisions by Regulatory Commissions

Exhibit AG-1.40 Peer Group Selection Screening

Exhibit AG-1.41 S&P and Moodys Credit Reports on CECo

Exhibit AG-1.42 Calculation of Impact of TCJA on Cash Coverage Ratios

Exhibit AG-1.43 DR Response – Equity Ratios of Utilities Unverified

Exhibit AG-1.44 DR Response – CMS Debt Rating Reports Refused

Exhibit AG-1.45 Values Line Report on Market Volatility vs. Risk

Exhibit AG-1.46 O&M Adjustments Summary

Exhibit AG-1.47 DR - Inflation Cost Adjustment Rerun with Staff Request

Exhibit AG-1.48 DR - Distribution O&M Expenses 2015 to 2022 & 2020 Actual

Exhibit AG-1.49 DR Response - Service Restoration Costs 2015-2020

Exhibit AG-1.50 DR Response – Storm Restoration Pre-Staging Staff & Cost

Exhibit AG-1.51 DR Response – Line Clearing Cost Increases

Exhibit AG-1.52 DR Response – Power Generation 2020 Actual O&M Expense

Exhibit AG-1.53 DR Response – Analytics & Outreach Staff 2019-2022

Exhibit AG-1.54 Uncollectible Accounts Expense

Exhibit AG-1.55 DR Response – Insurance Escalation Assumptions

Exhibit AG-1.56 Insurance Expense Test Year Calculation

Exhibit AG-1.57 DR Response – IT Investments Expense 2016-2018

Exhibit AG-1.58 DR Response – Cloud Computing Costs 2016-2022

Exhibit AG-1.59 DR Response – Incentive Comp Payouts and Operating Measures

Exhibit AG-1.60 DR Response – Other Employee Benefits

Exhibit AG-1.61 Pension and OPEB Plan Statement 2015-2022

Exhibit AG-1.62 Pension and OPEB Plans Expected Return Explanation

Exhibit AG-1.63 AG Revenue Deficiency Calculation

Exhibits for Witness David Dismukes:

Exhibit AG-2.1	Analysis of Historic Company Rates
Exhibit AG-2.2	Residential Non-Fuel Revenues per kWh, 2011-2020
Exhibit AG-2.3	Commercial Non-Fuel Revenues per kWh, 2011-2020
Exhibit AG-2.4	Industrial Non-Fuel Revenues per kWh, 2011-2020
Exhibit AG-2.5	Monthly Load Factor Under Alternative Peak Demands, 2020
Exhibit AG-2.6	Consumers' Monthly System Load Factor, 2016-2020
Exhibit AG-2.7	Modified Analysis of Company Production Allocation
Exhibit AG-2.8	Alternative Analysis of Consumers' Electric Generation Units -- 2020 Capacity Factors
Exhibit AG-2.9	Alternative Analysis of Consumers' Electric Generation Units -- Levelized Costs
Exhibit AG-2.10	Comparison of CCOSS Results, Under Alternative Production Demand Allocation Factors
Exhibit AG-2.11	Results of Alternative Class Cost of Service Study
Exhibit AG-2.12	Results of Company Class Cost of Service Study
Exhibit AG-2.13	Comparison of Company and Alternative Revenue Allocation
Exhibit AG-2.14	Comparison of Company and Alternative Proposed Rates

PROOF OF SERVICE - U-20963

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 22nd day of June 2021.

Celeste Gill Digitally signed by Celeste Gill Date: 2021.06.22 14:28:58 -04'00'

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