STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and other relief	))))	MPSC Case No. U-21490

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of

Attorney General Dana Nessel

April 22, 2024

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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 located at 5928 Southgate Rd., Rochester, Michigan 48306.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. I have testified in several regulatory proceedings before the Michigan Public Service Commission (MPSC or Commission) and other regulatory jurisdictions. I have prepared and/or filed testimony in rate case proceedings, revenue decoupling reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power Supply Cost Recovery (PSCR) cases. 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 settings and other regulatory proceedings.

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 in the last two years:

- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2022-2023 GCR reconciliation case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2022 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in the Indian Michigan Power Company's 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.

- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CCECo 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Michigan Department of Attorney General to perform an independent analysis of Consumers Energy Company's (CECo or the Company) gas rate case filing in Case No. U-21490. This testimony presents a report of that analysis with related recommendations.

Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?

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

1. The level of proposed rate base and capital expenditures;
2. The amount of working capital;

3. The Company's cost of capital;
4. Adjustments to forecasted sales and transportation volumes and related revenues for the projected test year;
5. The level of operations and maintenance expenses;
6. Depreciation and property tax adjustments;
7. Rate design issues; and
8. The sale of the Appliance Service Program and the passthrough of the proceeds to utility customers.

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 select 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 CMS Energy Investor Presentations
2. Exhibit AG-2 Security Analysts Reports
3. Exhibit AG-3 CPI Inflation Factors 2023 and 2024
4. Exhibit AG-4 Distribution MAOP Projects Cap Ex
5. Exhibit AG-5 Distribution Cathodic Protection Projects
6. Exhibit AG-6 Demand Augmentation Projects
7. Exhibit AG-7 EIRP Miles Retired, Installed and Costs
8. Exhibit AG-8 Distribution Line 1010 Disallowance
9. Exhibit AG-9 Vintage Service Replacement Program
10. Exhibit AG-10 Advanced Methane Detection System
11. Exhibit AG-11 PHMSA Rules on MAOP
12. Exhibit AG-12 Material condition Program 2023 Capex

13. Exhibit AG-13 Transmission MAOP Projects
14. Exhibit AG-14 Transmission Fiel Measurement Projects
15. Exhibit AG-15 Transmission Base pipeline Projects
16. Exhibit AG-16 Transmission Regulator Stations
17. Exhibit AG-17 Transmission City Gates projects
18. Exhibit AG-18 Transmission PLD
19. Exhibit AG-19 Compression Overisel
20. Exhibit AG-20 Compression Muskegon
21. Exhibit AG-21 Compression Northville
22. Exhibit AG-22 Compression St. Clair
23. Exhibit AG-23 Riverside Storage Field Retirement
24. Exhibit AG-24 Riverside Storage Field
25. Exhibit AG-25 Northville Dehydration Project
26. Exhibit AG-26 Storage Well Rehabilitation Program
27. Exhibit AG-27 Gas Compression 2023 Capex Underspent
28. Exhibit AG-28 IT Projects in Planning Phase
29. Exhibit AG-29 Order Tracking and Web Portal IT Projects
30. Exhibit AG-30 IT Gas Compression Historian
31. Exhibit AG-31 IT Gag Tracking and Traceability Project
32. Exhibit AG-32 IT Projects 2023 Underspent
33. Exhibit AG-33 Lansing Service Center
34. Exhibit AG-34 Hastings Service Center
35. Exhibit AG-35Kalamazoo Service Center
36. Exhibit AG-36 EIRP Support Projects
37. Exhibit AG-37 Operations Support 2023 Underspent
38. Exhibit AG-38 Security projects
39. Exhibit AG-39 AG Capex, Rate Base, Depreciation, Property Taxes Adjustments
40. Exhibit AG-40 Working Capital Adjustments Summary
41. Exhibit AG-41Working Capital – Accounts Receivable
42. Exhibit AG-42 Working Capital Inventory Value Adjustment
43. Exhibit AG-38 CECo Response Accrued Taxes

44. Exhibit AG-44 Overall Cost of Capital
45. Exhibit AG-45 Cost of Common Equity
46. Exhibit AG-46 Cost of Common Equity-DCF
47. Exhibit AG-47 Cost of Common Equity-CAPM
48. Exhibit AG-48 Cost of Common Equity-Risk Premium
49. Exhibit AG-49 Peer Group Utility and Non-Utility Business Mix
50. Exhibit AG-50 Market to Book Ratios of Peer Group
51. Exhibit AG-51 ROE Decisions by Regulatory Commissions
52. Exhibit AG-52 Cash Flow to Debt Coverage Ratio Recalculation
53. Exhibit AG-53 Moody's Report
54. Exhibit AG-54 S&P Report
55. Exhibit AG-55 CECo Response on Discussions with Rating Agencies
56. Exhibit AG-56 Value Line Market Volatility Not Risk
57. Exhibit AG-57 Gas Sales Analysis
58. Exhibit AG-58 CECo Response Sales Adjustments
59. Exhibit AG-59 AG Sales and Revenue Adjustments
60. Exhibit AG-60 O&M Summary Adjustments
61. Exhibit AG-61 Revised Uncollectible Accounts Expense
62. Exhibit AG-62 LAUF & Company Use Gas Adjustment
63. Exhibit AG-63 Health Care Costs
64. Exhibit AG-64 401-K Cost Adjustment
65. Exhibit AG-65 CECo Response – Staking and Location Program
66. Exhibit AG-66 CECo Response – Quality Lean Department
67. Exhibit AG-67 CECo Response – SIMP Costs
68. Exhibit AG-68 Corporate Reorganization Cost Savings
69. Exhibit AG-69 Transmission Pipeline Integrity Assessments
70. Exhibit AG-70 IT Expense 2023 Decline
71. Exhibit AG-71 AG Revised Revenue Requirement
72. Exhibit AG-72 Incentive Compensation Threshold
73. Exhibit AG-73 Appliance Program Historical Gross Margins

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 rate increase of $136 million. The rate increase represents an overall increase in base rates of 9% and an increase in residential base rates also of 9%. Including the cost of gas, the average residential gas bill would increase by approximately 5.7%. I have identified several cost disallowances to the Company's proposed cost levels and capital projects, that I recommend the Commission approve. As a result of these adjustments, I have determined that the Company has a revenue deficiency of $5.3 million. It should be noted that the Company reported a revenue sufficiency (surplus) of $2.3 million in 2022, which followed revenues surpluses of $17.7 million in 2021 and of $29 million in 2020. The Company also achieved a Return on Common Equity of 10.46% in 2022.[1] My conclusions and related adjustments are summarized below:

1. I recommend a reduction in capital expenditures of $410 million and a reduction of $385 million to rate base for the test year, including a $105 million adjustment to working capital. This reduces the Company's revenue deficiency by $30.7 million.
2. I recommend that the Commission adopt a lower cost of capital rate of 5.96%, a capital structure with 50% equity capital and a return on common equity of 9.85%. These recommendations reduce the Company's revenue deficiency by $35 million.

[1] Exhibit A-1, Schedule A1 and Schedule A-2.

3. I recommend a higher residential and commercial sales forecast, as well as higher commercial transportation gas deliveries, which increase distribution margin revenue by $21 million.

4. I recommend a lower level of Operations and Maintenance expenses for the test year. This reduces the Company's revenue deficiency by $35.3 million.

5. I recommend a lower amount of depreciation expense of $8.1 million and lower property tax expense of $2.8 million pertaining to the lower capital expenditures and additions to plant discussed above. These adjustments reduce the revenue deficiency by the same amount.

6. I recommend that the Commission retain the residential monthly customer charge remain at $13.60 or at most raise it to 14.60 and the Company's proposal to increase the monthly charge to $18.60 be rejected.

7. I recommend that the Commission retain the General Service GS-1 monthly customer charge at $16.00 or at most increase it to $17.00.

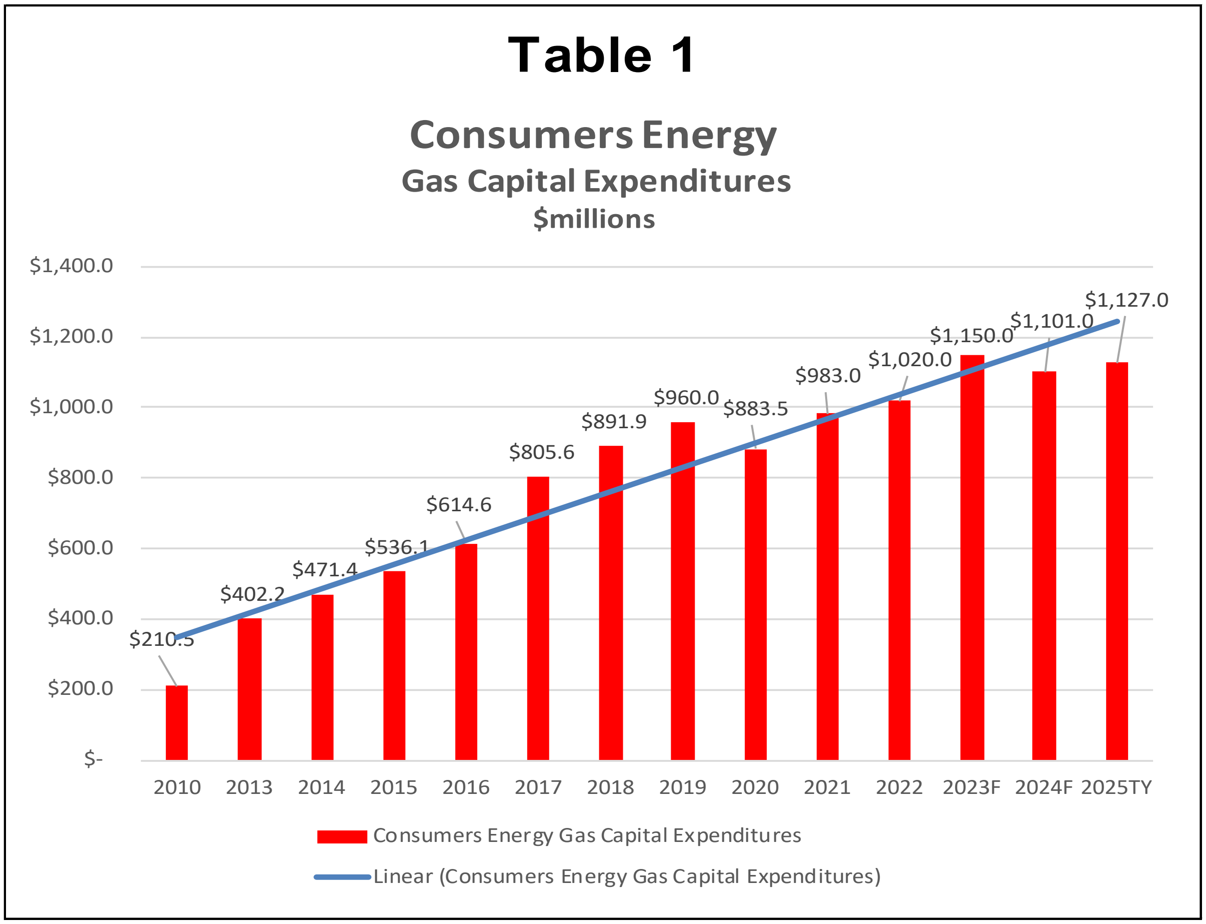
8. I recommend that the Commission order the Company to passthrough to customers 100% of the net proceeds and benefits from the sale of the Appliance Sale Program.

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

III. LARGE INCREASE IN RATE BASE AND CAPITAL EXPENDITURES

Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LEVEL OF CAPITAL EXPENDITURES PROPOSED BY THE COMPANY AND THE RESULTING INCREASE IN RATE BASE.

A. In this general rate case, CECo has proposed capital expenditures of $1.0 billion for 2022, $1.0 billion for 2023, $826 million for the 9 months ending September 2024 ($1.1 billion annualized), and an additional $1.1 billion for the 12 months ending September 2025. These increases are in addition to capital expenditures of $2.8 billion made during the prior three years from 2019 to 2021.[2] The following chart in Table 1 shows the dramatic increase in capital expenditures over recent years in comparison to more moderate amounts in prior years.



[2] Exhibit A-12, Schedule B-5 in MPSC Case Nos. U-21148, U-21308 and U-21490.

Until 2010, the Company was able to keep capital expenditures around $200 million annually. By 2022, about twelve years later, the level of capital expenditures has increased five-fold to $1.0 billion and continues at this high level into 2023 through 2025.

The capital expenditures have fueled an alarming increase in rate base. As shown below in Table 2, rate base has been growing at double digit rates in recent years, and the Company is proposing to increase rate base again in this rate case by 27% over the 2022 historical rate base to nearly $11 billion.

Table 2

Consumers Energy Gas Rate Base Growth 2010 to Projected 2023 Test Year

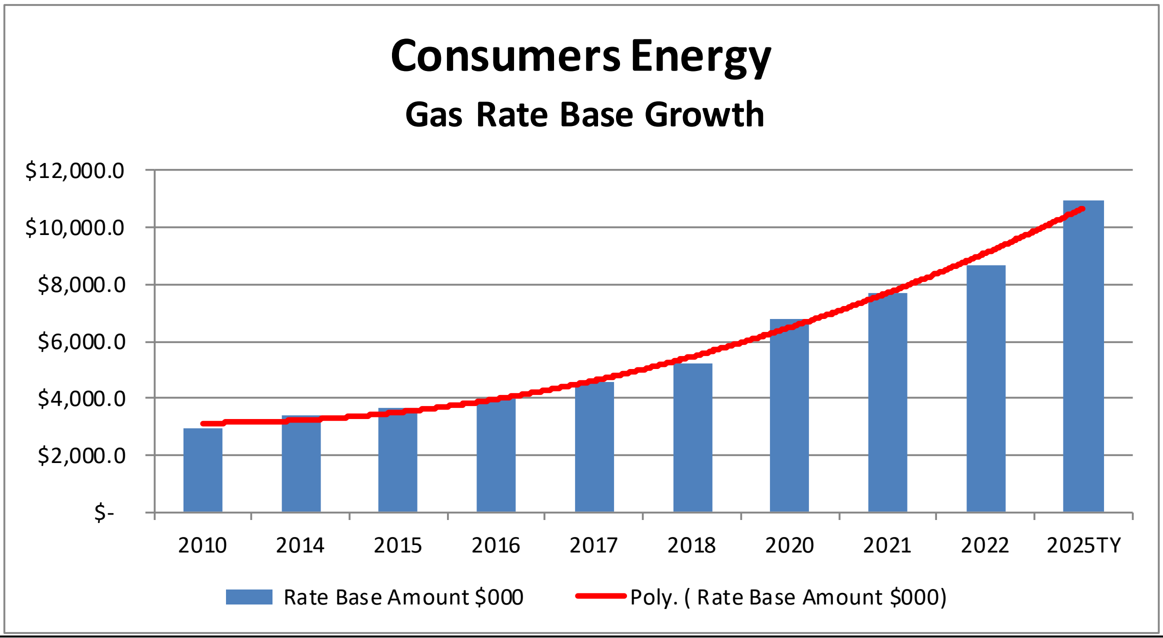
Rate Base Year	2010	2014	2015	2016	2017	2018	2020	2021	2022	2025TY
Docket No.	U-16855	U-17882	U-18124	U-18424	U-20322	U-20650	U-21148	U-21308	U-21490	U-21490
Rate Base [1] (Million)	$ 2,943.8	$ 3,399.3	$ 3,654.3	$ 4,020.0	$ 4,597.6	$ 5,200.3	$ 6,807.9	$ 7,670.9	$ 8,658.8	$ 10,970.0
Year over Year Change		15%	8%	10%	14%	13%	31%	13%	13%	27%
Cumulative Change over 2010 Rate Base		15%	24%	37%	56%	77%	131%	161%	194%	273%

[1] Historical actual rate base in each docket, except Case No. U-21308 Test Year proposed amount.

The significant increase in rate base is illustrated by the following chart included in Table 3, which shows the exponential trend of increases in recent years.[3] The current trend has significant negative implications on customer bills as discussed later in my testimony.

[3] Table 3 shows a Polynomial trend line (Poly.) to show the latest trend in rate base growth.

Table 3



Q. WHAT DO YOU BELIEVE IS DRIVING THIS DRAMATIC INCREASE IN CAPITAL EXPENDITURES AND RATE BASE SINCE 2010?

A. I believe there are two main drivers. First, replacement of aging infrastructure and new capital spending to address market growth have required an increase in capital expenditures, which may have accelerated investment to some degree. The Company continues to propose ever-increasing capital expenditures to replace cast iron mains, steel mains and related service lines with few limits. It is unclear what significant changes in the conditions of the pipes and related infrastructure have occurred since 2010 to justify the dramatic escalation in capital expenditures. In fact, the Company has provided no in-depth engineering studies and very limited evidence that there has been a major change in the integrity of its distribution system in the past decade.

The Company also has experienced moderate customer growth in its market area. However, moderate customer growth existed in prior years. Prior to 2010, CECo was able to manage replacement of aging infrastructure and invest in new facilities to meet market growth with more reasonable increases in rate base. Therefore, customer growth and replacement of aging infrastructure by themselves do not fully explain the significant increase in capital expenditures and rate base since 2010.

Second and perhaps a bigger driver is that the replacement of aging gas transmission, storage and distribution infrastructure has given the Company an opportunity to accelerate rate base growth to increase earnings growth. For utility companies, earnings growth is directly related to rate base growth. As shown in the tables above, large increases in capital expenditures result in double digit increases in rate base which in turn fuels earnings growth, dividend growth, and stock price appreciation for shareholders.

The Company's executive management team, which is largely the same for Consumers Energy and for CMS Energy, has been quite clear and aggressive in communicating to investors and securities analysts its goal of increasing earnings per share at an average annual rate of 6% to 8%. For a utility such as CECo with limited gas sales and revenue growth, the increase in earnings per share comes almost entirely from the increase in capital expenditures and rate base. Exhibit AG-1 includes pertinent sections of a CMS Energy's presentation to investors and securities analysts in February 2023 where Company management communicated its earnings per share, capital expenditures growth goals and achievements. Other recent presentations tell the same story. The presentations are devoid of any discussion of gas sales or revenue growth to propel earnings per share growth.

Even more troubling is management's recent pronouncement forecasting $17 billion in capital spending over the next 5 years with a large portion of that amount coming from the gas utility. Management has also communicated that capital spending opportunities exist in excess of $50 billion in the coming years. Exhibit AG-1 shows this forecast along with other supporting information. To punctuate this large escalation in capital spending and potentially even higher increases, Company management has communicated to Wall Street that the federal tax reform enacted in December 2017 has created more "headroom" in customer bills to increase capital expenditures to higher levels. A securities analyst report issued by Deutsche Bank on June 24, 2018, describes this pronouncement.

> Previously CMS have provided an overall $18B number for their 10-year capital plan, although for the last several investor presentations the specific 10-year number has been replaced with a longer-term opportunity pegged at >$50B. When or whether management will articulate a specific higher 10-year number they have made it clear that tax reform created around 4% of rate headroom on the customer bill with a rule of thumb that each 1% opens up the potential for $400M of additional capital investment….

A second analyst report issued by Wolfe Research on May 23, 2018, echoes the same sentiment about information communicated by Company management at an investor meeting. "There is no shortage of potential for capital deployment and tax reform has helped to create additional headroom in customer rates." The two analysts' reports are included in Exhibit AG-2. These goals have propelled the escalation of capital expenditures into 2022 and in subsequent years through the projected test year ending September 30, 2025. A catalyst for this extraordinary growth in capital expenditures has been the Company's Natural Gas Delivery Plan.

Q. HAVE YOU DETERMINED WHAT THE IMPACT ON RESIDENTIAL CUSTOMER BILLS COULD BE OVER THE COMING YEARS IF THE COMMISSION APPROVES THE PROPOSED RATE INCREASE AND THAT RATE OF INCREASE CONTINUES INTO FUTURE YEARS?

A. Yes. On page 131 of Exhibit A-43 (NPD-1), the Company shows the average historical monthly gas bills for residential customers through 2022 and projections for 2025 and 2030. The chart shows the average monthly gas bill increasing from approximately $90 in 2022 to $105 by 2030, or approximately 17% over 8 years. Although gas prices spiked in 2022, the Company's forecast may not capture the total increase in the residential gas bill if the proposed rate increase in this rate case is granted and the Company continues its aggressive capital spending program.

As shown in Table 3 above, the Company's rate base has been growing in double digits and from 2017 through the end of 2025 projected test year at an average annual rate of 13%. If we assume that the Company will continue on the current pace of capital expenditures and annual rate base growth of 13% annually, this growth rate accompanied by increases in operating expenses will more than double the actual 2022 annual gas bill of $1,076 in 10 years to $3,234 by 2031.[4] Table 4 below shows the potential increase in the average

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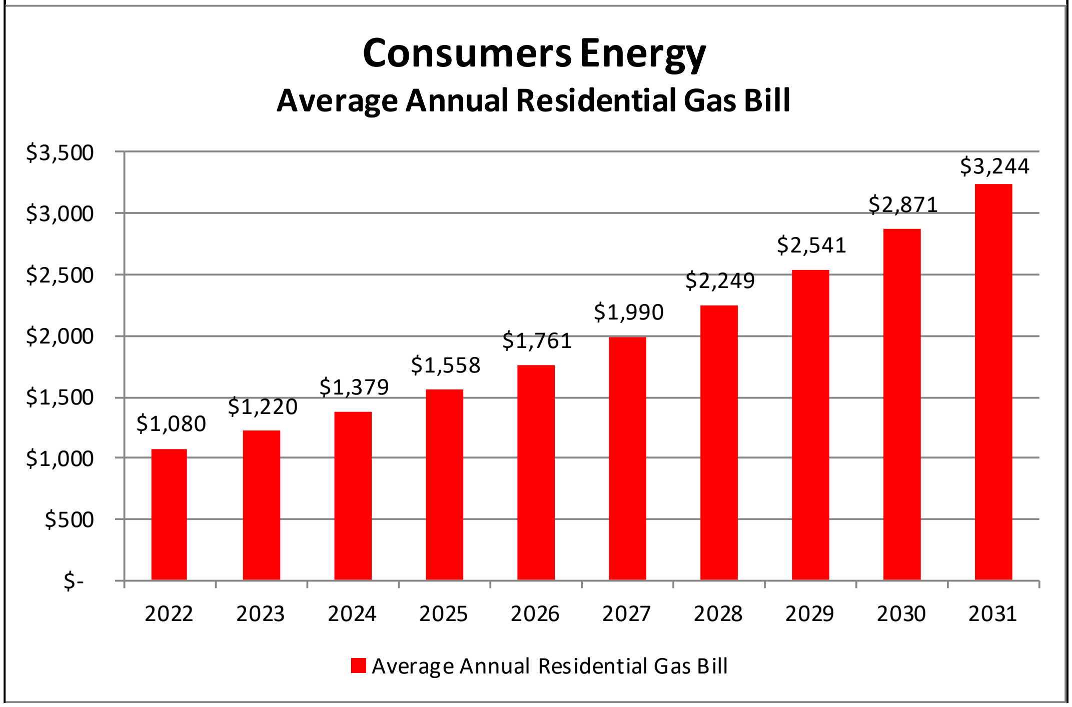
[4] In response to U-21308 DR AG-CE-0285, CECo provided a calculation of the actual average residential gas bill for 2022 showing the amount of $1,076 for the year and $89.70 average per month.

residential gas bill if the current trend in rate base growth continues and the price of natural supply remains the same as in 2022. Although gas prices have abated since 2022, with increased demand for natural gas and limited gas supply, they could reach or surpass those prices in future years.

Table 4



This potential escalation in annual customer bills is likely to pose a significant burden on residential customers with fixed income and low income. In addition, this potential increase in residential gas bills does not take into consideration further escalations in capital expenditures, which the Company seems to be contemplating as discussed above.

The compounding effect of large additions to rate base will continue to increase customer rates to unaffordable levels for many customers, particularly those in fixed and lower income brackets. This trend is not sustainable for customers. To avoid likely bill affordability problems in the future, the Company needs to moderate its capital spending in the coming years.

In prior years, when gas prices were at historical lows, the Company espoused the view that it was an opportune time to increase capital spending because customers would not feel the impact on their gas bills as much. However, that opportunity can vanish easily when natural gas prices increase significantly, especially if this ramp up in both O&M and capital spending is not moderated.

IV. Review of Capital Expenditures

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

A. Yes. I have analyzed the Company's forecasted capital expenditures by major department or area, and I have identified reasonable expenditure levels that the Commission should adopt. In projecting adjusted capital expenditures for 2024 and the projected test year where applicable I applied an inflation factor to the historical cost base to reflect inflationary cost pressure that the Company may face in those years. The inflation factors are 2.6% for 2024 and 2.2% for 2025. These rates reflect the increase in the forecasted Consumer Price Index during the 2024-2025 periods as shown in the Blue Chip Financial Forecast issued on March 1, 2024 and provided by the Company in response to discovery.[5]

[5] Exhibit AG-3 includes DR AG-CE-0199 ATT3 with the Blue Chip Report.

A. Distribution Plant

In Exhibit A-12 (LDW-1), Schedule B-5.10, the Company forecasted capital expenditures for various Distribution Plant capital programs of $197.9 million for 2023, $145.5 million for the 9 months ending September 2024, and $266.0 million for the 12 months ending September 2025. In comparison, the Company spent $223.6 million in 2022. In my testimony below, I will discuss certain programs where adjustments to the proposed capital expenditures should be made.

1. Regulatory Compliance Program

As shown in Exhibit A-118 (LDW-4), the Company forecasted capital expenditures for the Regulatory Compliance Program of $33.3 million for 2023, $31.3 million for the 9 months ending September 2024, and $117.2 million for the 12 months ending September 2025. Included in those amounts are capital expenditures for MAOP projects for large distribution pipelines and related facilities.[6] For 2023, the Company forecasted $2.9 million and for the 9 months ending September 2024 $7.2 million. For 12 months ending September 2025, the forecasted capital expenditures are $82.6 million.

Beginning on page 47 of his direct testimony, Mr. Warriner discusses the Distribution MAOP program and related regulations. Although these projects fall within recently issued regulations issued by the Pipeline Hazardous Materials Safety Administration (PHMSA), the genesis of the problem requiring the replacement or remediation of

[6] MAOP = Maximum Allowable Operating Pressure for a pipeline or related facilities.

pipelines to re-establish the MAOP is the lack of traceable, verifiable, and complete (TVC) records that should have been maintained by the Company. In response to discovery, the Company acknowledged and identified the missing records that prevent it from confirming the appropriate MAOP at which the pipeline should be currently operating.[7] Although the PHMSA rules provide for procedures and alternative steps that the Company can undertake short of replacing the pipeline to develop TVC records and to re-establish the MAOP,[8] the Company claims that it needs to replace 16 distribution pipeline segments, as identified in Table 17 on page 49 of Mr. Warriner's direct testimony.

In response to several discovery requests, the Company confirmed that it attempted to re-establish the MAOP through other means before concluding that replacement of the pipeline segments was necessary.[9] In discovery response AG-CE-0213, the Company also provided additional information on the current phase of each of the projects and related capital spending for 2023, the 9 months ending September 2024, and 12 months ending September 2025.[10]

Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES THAT THE COMPANY SEEKS TO INCLUDE IN RATE BASE FOR MAOP PROJECTS?

[7] Exhibit AG-4 includes DR AG-CE-0212.
[8] Exhibit AG-11 includes a copy of PHMSA rules.
[9] Exhibit AG-4 includes DR AG-CE-0213, 0214, 0215, and 0414.
[10] Id.

A. The reason for replacement of the pipelines under the MAOP projects is the direct result of the Company not having the appropriate records to verify that the pipelines can operate at the designed pressure level and not knowing their material properties and attributes that would assist in that verification. These are basic records that the Company should have in its possession from when the pipeline was installed. The PHMSA rules simply require that the Company check its records to verify it is operating the pipelines and related facilities at the MAOP specific to those facilities. The need to replace the pipelines emanates from the fact that the Company did not maintain the necessary records to perform the required verification.

Customers should not pay for the cost to replace pipelines due to the Company's failure to maintain appropriate records irrespective of when the pipeline was initially installed. The Company has the sole responsibility to maintain those records and periodically confirm that it is operating its pipelines at the appropriate allowable pressure. The PHMSA rules enacted in 2019 simply require that pipeline operators do now what they should have been doing all along. Therefore, the cost of replacing the pipeline segments under the MAOP projects should be borne entirely by the utility and not its customers. However, as a reasonable accommodation, given the age of the pipelines being replaced, the Commission could allow the Company to recover 50% of the cost of replacement and split the burden 50/50 between the Company and customers.

Q. IN HIS TESTIMONY AND RESPONSES TO DISCOVERY, MR. WARRINER STATES THAT LINE 1080 IS NOT BEING REPLACED BUT IS BEING

SUPPLEMENTED BY A SECOND LINE. DOES THAT PLAN CHANGE YOUR ASSESSMENT?

A. No. The reason why the Company needs to supplement Line 1080 with a second line is because Line 1080 can only operate at a limited pressure level due to the inability to pressure test the line given the lack of records to allow it to establish the pipeline design MAOP. By operating the line at a lower pressure based on available records, the Company cannot adequately meet customers' gas demand and now wants to install a second parallel line of 6.7 miles at a cost of $47.3 million. Therefore, this project would not exist but for the Company's lack of traceable, verifiable, and complete records for Line 1080.

Q. DID YOU DETERMINE THE AMOUNT OF CAPITAL EXPENDITURES THAT THE COMMISSION SHOULD REMOVE FROM THIS RATE CASE PERTAINING TO THE DISTRIBUTION MAOP PROJECTS?

A. Yes. There are two categories of projects that make up the Company's forecasted capital expenditures for Distribution MAOP projects. First, based on the Company's response to discovery request AG-CE-0213(b), the Company identified seven projects that are still in the planning phase or early stage of development with no design or engineering work yet completed.[11] It is premature to include these projects in rate base at this time for any amount. These projects are Line 1009c, Line 1002c, Line 1022, Line 1041, Line 1093, Line 1006, and Line 1026f. The total amount of capital expenditures that should be

[11] Id. includes DR AG-CE-0213(b).

removed for the seven projects is $1,243,000 for 2023, $1,270,000 for the 9 months ending September 2024 and $4,126,000 for the 12 months ending September 2025.

Second, the other six projects, Line 1080, Line 1009, Line 1022f, Line 1009/1009c, Line 1020, and Line 1087 have forecasted costs totaling $363,000 for 2023, $8,102,000 for the 9 months ending September 2024 and $58,301,000 for the 12 months ending September 2025. Also, as shown on page 2 of Exhibit A-118, the Company plans to complete MAOP projects under the $5 million threshold at a cost of $240,000 for 2022, $2,893,000 for 2023, $3,895,000 for the 9 months ending September 2024, and $5,220,000 for the 12 months ending September 2025. As discussed above, the Commission should disallow recovery of 50% of the capital expenditures for this group of projects. Therefore, I recommend that the Commission disallow $301,000 for the year 2023, $5,698,000 for the 9 months ending September 2024, and $31,625,000 for the 12 months ending September 2025.

In total for the Distribution MAOP projects, I recommend that the Commission disallow $1,544,000 for the year 2023, $6,968,000 for the 9 months ending September 2024, and $35,751,000 for the 12 months ending September 2025.

2. Cathodic Protection Program

As shown in Exhibit A-118 (LDW-4), the Company forecasted capital expenditures for the Cathodic Protection Program of $8.6 million for 2023, $6.9 million for the 9 months ending September 2024, and $9.8 million for the 12 months ending September 2025.

Mr. Warriner discussed the sub-programs under this capital expenditures category beginning on page 60 of his direct testimony. The category consists of three sub-programs: RMU Installation, Rectifier and Groundbed Installations/Replacements, and Other Capital Repairs. Mr. Warriner's testimony identifies the historical and forecasted capital spending for each sub-program. Although the forecasted spending for two of the three sub-programs generally tracks with historical spending, the Other Capital Repair costs increase significantly for 2024 and 2025 from the capital spending in 2022. For this sub-program, the Company forecasted capital expenditures of $8,629,402 for 2024 and $8,942,121 for 2025. In comparison, the Company spent $5,729,519 in 2022.

Q. WHAT IS YOUR ASSESSMENT OF CATHODIC PROTECTION PROGRAM SPENDING FOR 2024 AND 2025?

A. In response to discovery, the Company provided additional information on its spending plans in this capital expenditures category.[12] The information in response to DR AG-CE-0218 shows that for 2023, 2024, and 2025, the Company will not have any capital expenditures for RMU installations. For Rectifier and Groundbed Installations and Replacements, capital spending in 2023 was in line with 2022 levels at approximately $2.4 million and is forecasted to decline in 2024 and 2025 to less than $1.0 million. However, capital expenditures for Other Capital Repairs increased to nearly $10 million in 2023 from

[12] Exhibit AG-5 includes DRs AG-CE-0217, 0218, SA-CE-162 and 163.

$5.7 million in 2022. As stated earlier, the forecasted capital expenditures for this sub-program are $8,629,402 for 2024 and $8,942,121 for 2025.

The response to discovery request SA-CE-162 shows a significant increase in the number of work orders completed in 2023 at 1,239 versus 971 in 2022.[13] For 2024 and 2025, the Company forecasted the same number of work order to be completed at 971. The number of work orders in the past three years (2021 to 2023) ranged between 764 and 1,239 and averaged at 991. An even higher number of work orders were completed from 2018 through 2020, ranging from 1,246 to 1,711, but with lower capital spending of between $3.2 million and $5.1 million in this sub-program.

Based on the level of work order activity forecasted by the Company for 2024 and 2024, the forecasted capital expenditures are significantly overstated. Using the information from the most recent three years (2021-2023), the average capital spending on this sub-program was $6,921,000.[14] Adjusted for inflation, the forecasted capital spending for 2024 should be $7,101,000 and for 2025 should be $7,257,000.[15] The difference between these amounts and the Company's forecasted amounts are $1,528,000 lower for 2024 and $1,685,000 lower for 2025.[16]

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[13] Id. includes DR SA-Ce-162.
[14] Id. includes DR SA-CE-163.
[15] $6,921,000 x 1.026 = $7,101,000 x 1.022 = $7,257,000.
[16] For 2024: $7,101,000 – 8,629,000 = - $1,528,000. For 2025: $7,257,000 - $8,942,000 = -$1,685,000.

Therefore, I recommend that the Company's forecasted capital expenditures be reduced by $1,146,000 ($1,528,00 x 9/12) for the 9 months ending September 2024 and $1,646,000 for the 12 months ending September 2025.[17]

3. Capacity/Deliverability Program

As shown in Exhibit A-119 (LDW-5), the Company forecasted capital expenditures for the Capacity and Deliverability Program of $3.3 million for 2023, $4.9 million for the 9 months ending September 2024, and $5.6 million for the 12 months ending September 2025.

Mr. Warriner discussed the underlying projects beginning on page 65 of his direct testimony and identified the major historical projects in Table 19 on page 67 with the total amount of spending. Pages 68-70 provide some limited information on forecasted projects. The testimony on the forecasted projects does not provide sufficient insight on the cost, timing of the projects, and current phase of development. In response to discovery, the Company provided additional details including the current status of project development. The information provided by the Company shows that some of the projects with capital spending included in 2024 and 2025 have not yet completed the design phase and still require field surveys. No engineering work has been completed or construction has begun on these projects. One project has been cancelled since the Company's rate case filing.

[17] $1,528,000 x 3/12 + $1,685,000 x 9/12 = $1,646,000.

Discovery response AG-CE-0219 shows that the Freeman and Dale Rd./Midland project has been cancelled. This project had forecasted capital expenditures of $2.5 million in 2024. The Beaverton 12-inch HP Shaffer Rd. and the Rives Junction Road/Parnall Rd. projects have still not been surveyed, meaning that they are in the very early stage of development. The 2025 forecasted capital expenditures for the two projects are $3,670,511 and $356,068, respectively. In its forecast, the Company also has included forecasted capital expenditures for other projects in the amount of $463,035 for 2024 and $312,511 for 2025 with no details or project status disclosed.[18] These projects are still not sufficiently developed, too preliminary, and not adequately supported. The project costs are premature for inclusion in rate base in this rate case.

Therefore, I recommend that the Commission remove total capital expenditures of $2,222,000 for the 9 months ending September 2024 and $3,996,000 for the 12 months ending September 2025.[19]

4. Material Condition Program – EIRP Capital Expenditures

As shown on page 1 of Exhibit A-96 (KAP-4), the Company forecasted capital expenditures for the Enhanced Infrastructure Replacement Program (EIRP) of $208.0 million for 2023, $157.9 million for the 9 months ending September 2024, and $235.3

[18] Exhibit AG-6 includes DRs AG-CE-0219 and SA-CE-164.
[19] For 2024: ($2,500,000 + 463,035) = $2,963,000 x 9/12 = $2,222,000. For 2025: ($2,963,000 x 3/12) + ($3,670,511 + 356,068 + 312,511) x 9/12 = $3,996,000.

million for the 12 months ending September 2025. In comparison, the Company spent $248.1 million in 2022.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE EIRP.

A. In Case No. U-16855 filed in September 2011, the Company proposed a comprehensive main replacement program that would achieve the following objectives:

1. Replacement of all cast iron mains over the course of the 25-year program.
2. Replacement of all bare, oxyacetylene welded, threaded & coupled and cathodically-unprotected steel mains over the course of the 25-year program.
3. Replacement of 100 miles of transmission gas mains located in high consequence areas (HCA) over the 25-year program.
4. Replacement of approximately 70 miles of ERW piping located in gas storage fields and install launcher/receivers, as necessary, to permit future inspection by in-line inspection (ILI) technology.[20]

According to the direct testimony of Steven Beachum in that rate case, the Company would be able to achieve the 25-year replacement target with an annual capital spending level of $70 million. If that plan had been successful, full replacement of targeted mains would have been achieved by the year 2036, or 12 years from now. However, the Company's plan has not materialized at anything close to what was proposed in 2011.

At the beginning of the main replacement program, the Company had targeted replacement of 2,869 miles of mains, which over the 25-year plan period would have resulted in an annual replacement rate of 115 miles at an average annual capital spending level of $70

[20] MPSC Case No. U-16855, Steven Beachum direct testimony at page 33.

million, or $609,000 per mile. During the 12 years from 2012 to 2023, the Company retired approximately 784 miles of the targeted old mains plus other at-risk mains for a total of 899 miles of retired mains. The Company replaced those mains by installing 935 miles of new mains at a cost of $1.084 billion, or $1.159 million per mile. The retirement rate per year on the old, targeted mains has been 75 miles of main instead of the planned 115 miles per year. Even more concerning, the Company had projected it would cost $609,000 to replace a mile of main when it announced the program in 2011.[21] The actual average cost over the past 12 years has been $1.159 million per mile, or nearly two times the original estimate. Exhibit AG-7 includes the Company's response to discovery requests AG-CE-0356 and 0357 with the information discussed above and additional program details.

In addition to the base distribution system pipe replacement program, the Company also includes in the EIRP the replacement of steel pipe for Transmission lines Operated by the Distribution department. These are referenced or identified as TOD projects. During the 12 years from 2012 to 2023, the company retired approximately 47 miles of TOD mains and replaced them with 50 miles of new main at a cumulative cost of $146.4 million.[22]

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[21] $70 million per year divided by 115 miles of main targeted for replacement annually over a 25-year period equals to an average cost per mile of $609,000.
[22] Exhibit AG-7.

Q. IN YOUR REVIEW OF COMPANY WITNESS KRISTINE PASCARELLO'S DIRECT TESTIMONY ON THE EIRP, WHAT KEY FINDINGS DID YOU DISCOVER?

A. In reviewing Ms. Pascarello's direct testimony and responses to discovery, I identified four major areas that will affect the capital spending plans for 2024 and 2025. First, the cost of main replacement within the grid program increased in 2023 to $1,580,480 per mile versus the $1,394,220 cost per mile in 2022. This is a 13.4% increase. The Company states that it had targeted a cost per mile of $1,680,794 for 2023 and claims it achieved an improvement of approximately $100,000.[23] However, the reality is that the cost per mile increased significantly in 2023 and the Company continues to forecast additional increases of 2.1% in 2024 and 6.3% in 2024.

First, beginning on page 38 of her direct testimony, Ms. Pascarello lists some of the factors that can affect the cost per mile from year to year, but over multiple years those factors should average out with some years having lower costs and other years higher costs. However, the trend has been up over multiple years, meaning that the factors identified by Ms. Pascarello are not always determinative of the outcome. Although permitting costs and dual main installations may have increased recently, the Company needs to push back and negotiate lower fees and installation requirements with the requesting municipalities. On page 42 of her testimony, Ms. Pascarello lists certain initiatives to improve the cost per mile of main installed, but those initiatives are not reversing the trend for 2023 and the

[23] Id. includes DR AG-CE-0361.

next two years. This rising cost per mile is also increasing the total cost of the program for the same miles of main installed.

Second, in coming years, the Company plans to shift the program toward more replacement of at-risk pipe segments instead of using the grid approach. This is a significant shift in strategy after the Company moved to the grid approach only a few years ago on the premise that it would be more efficient, less costly per mile, and less disruptive to customers. This change does not seem to bode well for reducing EIRP program costs.

Third, the Company plans to significantly increase the number of miles of TOD high pressure steel pipe to be replaced in 2024 and 2025 with a commensurate large increase in costs. While in last five years the Company has replaced and installed between 1 to 6 miles of TOD pipe annually at a cost ranging from $2.3 million to $28 million, for 2024, the Company proposes to replace 5.6 miles and install 8.7 miles of high pressure main at a cost of $42,176,742. For 2025, the Company proposes to install 20.8 miles of main at a cost of $79 million. This sub-program is spurring a large increase in the overall cost of the EIRP for 2024 and 2025.

Fourth, the amount of capital spending on the entire EIRP continues to escalate. Although the Company actually spent $181.9 million in 2023 after forecasting $208.2 million for the year, the Company plans to spend $219.3 million in 2024 and $241.6 million in 2025. These are increases of 20% in 2024 over 2023 and an additional 10% in 2025 for a cumulative increase of 30%.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE COMPANY'S FORECASTED EIRP CAPITAL EXPENDITURES FOR THE 2024 AND 2025 FORECASTED PERIODS?

A. The increasing cost trend shown above is not sustainable from a customer affordability viewpoint and must be reversed. The Commission should set a maximum spending level or a cap for the EIRP to avoid the current runaway cost of the program. Most homeowners must live within their own cost budgets and do not have unlimited resources to be able to afford ever increasing household costs. They make hard choices every day as to where to spend their money within the available resources. Similarly, the Company needs to set an annual budget and replace and install the number of miles of main that can be completed within a set budget cap. The current practice of unlimited and increasing capital spending on the EIRP program needs to be restrained.

Based on the actual spending of $181,926,631 in 2023 and adjusting that amount for forecasted inflation of 2.6% in 2024, I propose a spending budget cap of $187 million for 2024, or $140 million for the 9 months ending September 2024.[24] For 2025, after adjusting for inflation, I propose a spending cap of $191 million, or $190 million for the 12 months ending September 2025.

Although the lower spending level that I propose may reduce somewhat the number of miles that the Company planned to retire and install in 2024 and 2025, the inflation

[24] $187,000,000 x 9/12 = $140 million.

adjusted spending cap from 2023 should accord the Company the ability to retire approximately 120 miles of pipe as it did in 2023. The lower capital spending level will also give the Company added incentive to reduce the cost per mile of main installed and reduce pressure on scarce resources. The Company is competing for limited resources, whether through the direct hire of employees or through subcontractors, and also for materials and equipment, with other utilities around the country, as those utilities also have undertaken large pipe replacement programs. This competition for limited resources has contributed to the higher cost of pipe replacement under the Company EIRP program during recent high inflationary periods. A more moderate pace of pipe replacement will help take the pressure off the competition for those resources.

It is also noteworthy to point out that through the risk-based approach to pipe replacement that the Company has employed over the past 12 years, most of the high-risk mains and services should already have been replaced. The Company has not provided any compelling evidence that the planned increase in spending is tied to any increased safety risks. Therefore, if the completion of the EIRP program is extended a few more years past the current 2035 date, it is a reasonable trade-off to balance against customer affordability from uncontrolled capital spending on the program.

Therefore, I recommend that the Commission approve capital expenditures of the 9 months ending September 2024 at $140 million and $190 million for the 12 months ending September 2025. In comparison to the Company's forecasted capital expenditures of $157,943,000 and $235,344,000, the Commission should remove $17,943,000 for the 9 months ending September 2024 and $45,344,000 for the 12 months ending September 2025.

5. Material Condition Non-Modeled Program

As shown on page 1 of Exhibit A-96 (KAP-4), the Company forecasted capital expenditures for the Material Condition Non-Modeled Program of $29.9 million for 2023, $23.3 million for the 9 months ending September 2024, and $34.7 million for the 12 months ending September 2025. In comparison the Company spent $41.0 million in 2022.

Ms. Pascarello discusses this program beginning on page 46 of her direct testimony. In contrast with the EIRP, which is a planned replacement of deteriorating pipelines and services, the Material Condition Non-Modeled program addresses emergent needs for pipe replacement and other work that arise during the year. On page 51 of her testimony, Ms. Pascarello discloses that the forecasted capital expenditures for 2024 and 2025 include the cost to replace Line 1010. This line is a MAOP project similar to the other projects discussed earlier in my testimony, which is being done under the Material Condition Non-Modeled program. As stated in her testimony, the reason to replace this line is the Company's incomplete pressure test documentation and lack of other traceable, verifiable, and complete records from the original installation of the pipeline. Although this pipeline was purchased from another utility, the responsibility to maintain complete, accurate and adequate records still falls on the Company and customers should not pay the full cost to replace the pipeline due to those failures.

Therefore, I recommend that the Commission disallow 50% of the cost to replace this pipeline. In response to discovery, the Company disclosed that it included capital expenditures of $5,499,385 in the 9 months ending September 2024 and $9,850,000 in the 12 months ending September 2025.[25] Based on those amounts, I recommend that the Commission disallow $2,750,000 for the 9 months ending September 2024 and $4,925,000 for the 12 months ending September 2025.

6. Vintage Services Replacement Program

As shown on page 1 of Exhibit A-96 (KAP-4), the Company forecasted capital expenditures for the Vintage Service Replacement Program of $12.4 million for 2023, $14.4 million for the 9 months ending September 2024, and $28.5 million for the 12 months ending September 2025. In comparison the Company spent $17.2 million in 2022.

Ms. Pascarello discusses this program beginning on page 60 of her direct testimony. This program replaces deteriorating service lines both in conjunction with the EIRP and ~~also~~ outside of the EIRP. Beginning in 2022, the Company began to align replacement of vintage services with the replacement of mains under the EIRP to avoid duplicating work by replacing services before the associated mains were replaced. From Table 6 on page 64 of Ms. Pascarello's testimony, it appears that this effort resulted in fewer non-EIRP services replacements in 2022 and 2023. Where in the three years prior to 2022, the Company replaced more than 5,000 service under the VSR program annually; in 2022 the forecasted number declined to 2,176, and in 2023 it declined further to 1,519 services. In

[25] Exhibit AG-8 includes DR AG-CE-0365.

response to discovery, the Company reported that the actual number of services replaced in 2023 was even less at 1,219.[26]

However, for 2024, the Company forecasted nearly double the number of services to be replaced under the VSR program to 2,474 with another large increase to 4,164 services forecasted for 2025. These quantities are excessive and go counter to the declines observed in 2022 and 2023. From the discussion in Ms. Pascarello's testimony, it is not clear why a resumption of a large replacement program is necessary. For example, the gas leak data provided on page 60 of her testimony shows a decline in the number of leaks from all types of gas services in the past two years. The higher number of service replacements is not adequately supported and should be scaled back.

I recommend that the average number of services replaced in 2022 and 2023 be used as a basis to forecast capital expenditures for this program for 2024 and 2025. The average number over those two years is 1,702. In DR AG-CE-0368, the Company provided a cost of $7,496 per service for 2024 and $7,501 for 2025. By applying these unit costs to the 1,702 units, I arrived at forecasted capital expenditures of $12,758,000 for 2024 and $9,568,000 for the 9 months ending September 2024.[27] I calculated capital expenditures of $13,007,000 for 2025, and $12,945,000 for the 12 months ending September 2025.

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[26] Exhibit AG-9 includes DR AG-CE-0368.
[27] 2024: 1,702 units x $7,496 = $12,758,000 x 9/12 = $9,568,000. For 2025: 1,702 units x $7,642 = $13,007,000 x 9/12 + $12,758,000 x 3/12 = $12,945,000.

Based on those calculations, I recommend that the Commission remove the excessive capital expenditures of $4,795,000 for the 9 months ending September 2024 and $15,551,000 for the 12 months ending September 2025.[28]

7. Gas Distribution Other Programs

In Exhibit A-97 (KAP-5), the Company included forecasted capital expenditures for Compliance and Controls Projects of $873,000 for 2023, $2.2 million for the 9 months ending September 2024, and $5.1 million for the 12 months ending September 2024. Included in these amounts are capital expenditures for the Advanced Methane Detection (ADM) system.

The Company began phase 1 implementation of the AMD system in 2021 and completed it in 2022 for a total capital cost of $7,035,000.[29] Based on information disclosed in the prior rate case U-21308, Phase 2 of the project was to start in 2023. Based on the information provided in Table 7 on page 67 of Ms. Pascarello's direct testimony, it appears that Phase 2 was delayed to 2024. The Company now forecasted capital expenditures of $1,539,370 for 2024 and $4,771,746 for 2025. In addition, the Company also forecasted O&M expense of $199,596 for 2024 and $432,834 for 2025 to support this project development. Based on these two amounts, the forecasted O&M expense for the projected test year is $374,525.

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[28] $9,568,000 - $14,363,000 = -$4,795,000 and $12,945,000 - $28,496,000 = -$15,551,000.
[29] Exhibit AG-10 includes DR AG-CE-0373 ATT_1.

On pages 67 through 73, Ms. Pascarello discusses the features of the ADM system and the purported ability of the system to detect very small gas leaks that current equipment supposedly cannot detect.

Q. WHAT IS YOUR ASSESSMENT OF THE AMD PROJECT?

A. At a cost of more than $14.4 million, assuming no further costs past 2025, the AMD system is a very costly system. Despite the Company's claims and self-serving information from the marketing brochures from the vendor, there is insufficient evidence that the new system will detect significant additional gas leaks of a threatening nature that are currently missed by existing equipment. In response to discovery, the Company states that it has not had problems identifying true gradable gas leaks using its existing traditional leak detection tools. Asked to provide quantifiable evidence of the value proposition of the new system, the Company provided a general statement that the AMD increases public safety without providing any evidence to support that statement and stating that value propositions have not been quantified.[30]

Although Ms. Pascarello references discussions with other utilities who have acquired the system, when asked to describe what value these utilities have garnered from the new system, her response was that the Company has not engaged in conversations with peer utilities about AMD cost/benefits or value decisions.[31] It is astonishing that the Company

[30] Id. includes DR AG-CE-0370.
[31] Id. Includes DR AG-CE-0371.

would propose to invest more than $14 million in a new system without performing basic due diligence to determine that the system actually provides incremental value.

In her testimony, Ms. Pascarello claims that the AMD will be required under the PHMSA Advisory Bulletin. In response to discovery on this item, it is not clear that this statement is credible. The discovery request asked the Company to provide evidence to support that statement and none was provided.[32]

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. Given the uncertainties of what quantifiable benefits the AMD system will create and given the high cost of $14.4 million, I recommend that the Commission reject the Company's proposed capital expenditures of $7,035,000 incurred in 2001 and 2022, and the forecasted amounts of $1,539,000 for the 9 months ending September 2024, and $4,772,000 for the 12 months ending September 2025, as shown on page 3 of Exhibit A-97(KAP-5).

8. Material Condition Program – 2023 Underspent

Q. ARE THERE OTHER ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL EXPENDITURES FOR THE MATERIAL CONDITION PROGRAM?

A. Yes. In response to discovery, the Company provided the actual capital expenditures incurred for 2023 in the Material Condition Program. The report shows that the Company

[32] Id. includes DR AG-CE-0374.

underspent the forecasted capital expenditures for 2023 included in rate base in this rate case. The Company had forecasted it would spend $283,297,000 on page 1 of Exhibit A-96 and spent $266,297,000.[33] The underspent amount was $17,000,000 or 6%.

The underspent amount cannot remain in rate base. The Company would be earning a return and recover depreciation expense on costs that it did not incur because that amount was not actually spent. Therefore, I recommend that the Commission remove the $17,000,000 from rate base.

B. Transmission Plant - Capital Expenditures

In Exhibit A-12 (MPG-2), Schedule B-5.5, the Company shows forecasted capital expenditures for Transmission Plant of $331.7 million for 2023, $267.3 million for the 9 months ending September 2024, and $224.7 million for the 12 months ending September 2025. In comparison, the Company spent $259.3 million in 2022. The three programs within the Transmission area are Asset Relocation, Regulatory Compliance, and Capacity/Deliverability. In my testimony below, I propose adjustments to the capital expenditures in several areas.

1. Regulatory Compliance – MAOP Project

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED TRANSMISSION MAOP PROJECTS AND RELATED CAPITAL EXPENDITURES.

[33] Exhibit AG-12 includes DR AG-CE-0379 and Attachment 1.

A. Beginning on page 10 of his direct testimony, Mr. Griffin discusses the various activities under the Regulatory Compliance Program, including the replacement of transmission pipeline under MAOP projects. The issues here are the same as in the Distribution MAOP projects. The Company lacks traceable, verifiable, and complete records to re-establish the MAOP of the targeted pipelines and has decided to replace those pipelines or segments of pipelines. As stated earlier in my testimony under the Distribution MAOP projects, customers should not pay for the cost to replace the affected pipeline because of the failure by the Company to have and maintain accurate and complete records on its pipelines.

Exhibit A-57 (MPG-4) shows MAOP Compliance Pipeline capital expenditures of $612,000 for 2022, $5.3 million for 2023, $478,000 for 9 months ending September 2024 and $3.5 million for the 12 months ending September 2025. Workpaper WP-MPG-2 lists the MAOP projects and related capital expenditures from 2022 through 2025. With the exception of project 9059 (Line 1900 Metamora City Gate Hot Trap Replacement) near the bottom of the workpaper, I recommend that the Commission disallow 50% of the actual and forecasted capital expenditures from 2022 to the end of the projected test year. For project 9059, I recommend that the Commission remove 100% of the forecasted costs for the 12 months ending September 2025. According to the Company, no work had begun on this project as of April 2, 2024.[34] Therefore, insufficient project development work has been completed on this project and it is premature to include the forecasted capital expenditures in this rate case.

[34] Exhibit AG-13 includes WP-MPD-2 and DRs AG-CE-276 and 0285.

In total, based on the cost information presented in WP-MPG-2, I recommend that the Commission remove capital expenditures of $306,000 for 2022, $2,638,000 for 2023, $239,000 for 9 months ended September 2024, and $2,884,000 for the 12 months ending September 2025.[35]

2. Deliverability Field Measurement Projects

Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR DELIVERABILITY FIELD MEASUREMENT PROJECTS.

A. On line 3 of page 1 of Exhibit A-58 (MPG-5), the Company included forecasted capital expenditures for Field Measurement projects of $6.1 million for 2023, $4.7 million for 9 months ending September 2024, and $11.0 million for the projected test year. In workpaper WP-MPG-3, the Company provides the list of projects that comprise the total capital expenditures. In response to discovery, the Company provided additional details for select larger projects, such as the current phase of development in early April 2024.

Attachment 1 to discovery response AG-CE-0286 shows that six of the listed projects have not yet been designed and will be entering the design phase later in the year.[36] These projects are still in the early phase of development with no assured timeline and thus premature to include in rate base in this rate case. Therefore, I recommend that the

[35] These amounts represent 50% of the total expenditures for each period in WP-MPG-2 with the exception of the projected test year where 100% of project 9059 has been included.
[36] Exhibit AG-14 includes DR AG-0286 with attachment 1.

Commission disallow $9,424,000 of capital expenditures for the six projects, other than project GM-01024, for the projected test year.

3. Deliverability Base Pipeline Program

Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR THE DELIVERABILITY BASE PIPELINE PROGRAM.

A. On line 4 of page 1 of Exhibit A-58 (MPG-5), the Company included forecasted capital expenditures for the Deliverability Base Pipeline program of $24.1 million for 2023, $16.5 million for 9 months ending September 2024, and $21.5 million for the projected test year. In workpaper WP-MPG-4, the Company provides the list of projects that comprise the total capital expenditures. In response to discovery, the Company provided additional details for select larger projects, such as the current phase of development as of early April 2024.

The attachment to discovery response AG-CE-0287 shows that for five of the listed projects no work has yet been done and no design has been completed. The five projects are: GL-02662, GL-03317, 13515, 13700, and 12920.[37] These projects are still in the early phase of development with no assured timeline and thus premature to include in rate base in this rate case. Therefore, I recommend that the Commission disallow $7,753,000 of capital expenditures for the five projects for the projected test year.

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[37] Exhibit AG-15 includes WP-MPG-4 and DR AG-0287 with attachment.

4. Regulator Stations-Distribution

Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR THE REGULATOR STATIONS DISTRIBUTION PROGRAM.

A. On line 5 of page 1 of Exhibit A-58 (MPG-5), the Company included forecasted capital expenditures for the Regulator Stations Distribution program of $31.5 million for 2023, $30.1 million for 9 months ending September 2024, and $39.4 million for the projected test year. In workpaper WP-MPG-5, the Company provides the list of projects that comprise the total capital expenditures. In response to discovery, the Company provided additional details for select larger projects, such as the necessity of the projects and the current phase of development as of early April 2024.

Attachment 1 to discovery response AG-CE-0288 shows that for 8 of the listed projects no design has yet been completed. The 8 projects are: GM-00939, GM-00947, 12892, 12899, 12905, 12907, 13780, and 13781.[38] These projects are still in the early phase of development with no assured timeline and thus premature to include in rate base in this rate case. Therefore, I recommend that the Commission disallow capital expenditures of $2,801,000 for the 9 months ending September 2024 and $8,433,000 for the projected test year.

[38] Exhibit AG-16 includes DR AG-0288 with attachment.

5. T&S City Gate Projects

Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR CITY GATE PROJECTS.

A. On line 6 of page 1 of Exhibit A-58 (MPG-5), the Company included forecasted capital expenditures for T&S City Gates of $29.8 million for 2023, $38.6 million for 9 months ending September 2024, and $51.7 million for the projected test year. In workpaper WP-MPG-6, the Company provided the list of projects that comprise the total capital expenditures. In response to discovery, the Company provided additional details for select larger projects, such as the necessity of project and the phase of development of the project as of early April 2024.

Attachment 1 to discovery response AG-CE-0291 shows that 9 projects were still in the early stages of development at Pre-Engineering/Design with no engineering/design yet completed.[39] The 9 projects are: 11189, GM-01052, 13204, 13231, 13232, 13233, 13234, 13235, and 13236. It is premature to include those projects in rate base given the early stage of development and charge customers for costs that may not occur during the projected periods. Therefore, I recommend that the Commission disallow $416,000 of capital expenditures for the 9 months ending September 2029, and $10,138,000 for the projected test year based on the amounts shown in WP-MPG-6 for the applicable projects.

[39] Exhibit AG-17 includes WP-MPG-6 and DR AG-0291 with attachment 1.

6. Pressure Limiting Devices (PLD)

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU ARE PROPOSING TO THE CAPITAL PROJECTS FOR PLD PROJECTS.

A. On page 1, line 2, of Exhibit A-59 (MPG-6), the Company forecasted capital expenditures for PLD projects of $12.2 million for 2023, $3.1 million for the 9 months ending September 2024, and zero for the 12 months ending September 2025. WP-MPG-8 provides a list of projects with the related cost. In response to discovery, the Company provided additional details for project GL-01656, including the necessity of the project and its current phase of development as of early April 2024.

Discovery response AG-CE-0293 reports that the project is currently in the evaluation stage, indicating that it is still in the early planning stage of development with no engineering/design yet completed.[40] It is premature to include this project in rate base given that it is still being evaluated whether it should be pursued further. Customers should not be charged for costs that may not occur during the projected periods. Therefore, I recommend that the Commission disallow $3,149,000 for the projected test year.

C. Gas Compression & Storage - Capital Expenditures

On page 1 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company forecasted capital expenditures for Gas Compression and Storage projects of $121.9 million for 2023, $148.8 million for the 9 months ending September 2024, and $220.4 million for the 12 months

[40] Exhibit AG-18 includes WP-MPG-8 and DR AG-0293.

ending September 2025. In comparison, the Company spent $118.9 million in 2022. Included in these amounts are capital expenditures for projects where I will recommend certain adjustments as discussed in my testimony below.

1. Overisel Compressor Station

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS TO RATE BASE YOU RECOMMEND FOR THE OVERISEL COMPRESSOR STATION.

A. On page 2, line 5, of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company shows forecasted capital expenditures for the Overisel Compressor Station of $27.5 million for 2023, $16.8 million for the 9 months ending September 2024, and $15.9 million for the 12 months ending September 2025. In workpaper WP-TKJ-5, the Company listed the projects that comprise the costs for the forecasted periods. In discovery, the Attorney General asked the Company to provide additional details for projects of $3 million or greater, including the current phase of development.

In response to the discovery request, the Company reported that the Engine Exhaust Emissions Control project is still in the initiation and planning phase. The capital expenditures pertaining to this project (Project#13149) are $5,787,000 for the 9 months ending September 2024 and $4,991,000 for the 12 months ending September 2025.[41]

The project is still in the early phase of development. It is premature to include this project in rate base at this time given the uncertainty of whether the project will proceed to

[41] Exhibit AG-19 includes WP-TKJ-5, page 2, and DR AG-CE-0310.

completion, or the costs will be incurred as forecasted. Therefore, I recommend that the Commission remove the forecasted capital expenditures of $5,787,000 for the 9 months ending September 2024, and $4,991,000 for the 12 months ending September 2025 from this rate case.

2. Muskegon Compressor Station

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS TO RATE BASE YOU RECOMMEND FOR THE MUSKEGON COMPRESSOR STATION.

A. On page 2, line 3, of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company shows forecasted capital expenditures for the Muskegon Compressor Station of $4.7 million for 2023, $10.0 million for the 9 months ending September 2024, and $19.8 million for the 12 months ending September 2025. In workpaper WP-TKJ-5, the Company listed the projects that comprise the costs for the forecasted periods. In discovery, the Attorney General requested the Company to provide additional details for projects of $3 million or greater, including the current phase of development.

In response to the discovery request, the Company reported that the Unit Overhaul and the Engine Exhaust Emissions Control project are still in the initiation and planning phase. The capital expenditures pertaining to these projects (Project# 13813 and Project # 6435) are $3,007,000 for the 9 months ending September 2024 and $15,185,000 for the 12 months ending September 2025.[42]

[42] Exhibit AG-20 includes WP-TKJ-5, page 1, and DR AG-CE-0308.

The two projects are still in the early phase of development. It is premature to include those projects in rate base at this time given the uncertainty of whether the projects will proceed to completion, or the costs will be incurred as forecasted. Therefore, I recommend that the Commission remove the forecasted capital expenditures of $3,007,000 for the 9 months ending September 2024, and $15,185,000 for the 12 months ending September 2025 from this rate case.

3. Northville Compressor Station

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS TO RATE BASE YOU RECOMMEND FOR THE NORTHVILLE COMPRESSOR STATION.

A. On page 2, line 4 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company shows forecasted capital expenditures for the Northville Compressor Station of $3.6 million for 2023, $4.9 million for the 9 months ending September 2024, and $11.3 million for the 12 months ending September 2025. In workpaper WP-TKJ-5, the Company listed the projects that comprise the costs for the forecasted periods. In discovery, the Attorney General requested the Company to provide additional details for projects of $3 million or greater, including the current phase of development.

In response to the discovery request, the Company reported that the Engine Exhaust Emissions Control project is still in the initiation and planning phase. The capital expenditures pertaining to this project (Project#13817) are $1,432,000 for the 9 months ending September 2024 and $4,936,000 for the 12 months ending September 2025.[43]

The project is still in the early phase of development. It is premature to include this project in rate base at this time given the uncertainty of whether the project will proceed to completion, or the costs will be incurred as forecasted. Therefore, I recommend that the Commission remove the forecasted capital expenditures of $1,432,000 for the 9 months ending September 2024, and $4,936,000 for the 12 months ending September 2025 from this rate case.

<u>4. St. Clair Compressor Station</u>

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS TO RATE BASE YOU RECOMMEND FOR THE ST. CLAIR COMPRESSOR STATION.

A. On page 2, line 7 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company shows forecasted capital expenditures for the St. Clair Compressor Station of $4.4 million for 2023, $4.5 million for the 9 months ending September 2024, and $6.7 million for the 12 months ending September 2025. In workpaper WP-TKJ-5, the Company listed the projects that comprise the costs for the forecasted periods. In discovery, the Attorney General requested the Company to provide additional details for projects of $3 million or greater, including the current phase of development.

[43] Exhibit AG-22 includes WP-TKJ-5, page 4, and DR AG-CE-0311.

In response to the discovery request, the Company reported that the Blowdown Vent Stack project is still in the initiation and planning phase. The capital expenditures pertaining to this project (Project#13808) are $1,959,000 for the 9 months ending September 2024 and $2,925,000 for the 12 months ending September 2025.[44]

The project is still in the early phase of development. It is premature to include this project in rate base at this time given the uncertainty of whether the project will proceed to completion, or the costs will be incurred as forecasted. Therefore, I recommend that the Commission remove the forecasted capital expenditures of $1,959,000 for the 9 months ending September 2024, and $2,925,000 for the 12 months ending September 2025 from this rate case.

5. Riverside Storage Field Retirement

Q. PLEASE IDENTIFY THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR THE PLANNED RETIREMENT OF THE RIVERSIDE STORAGE FIELD.

A. On line 18 of page 2 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company shows the forecasted capital expenditures for the Riverside Field Retirement project at $12.1 million for 2023, $33.3 million for the 9 months ending September 2024, and $37.1 million for the 12 months ending September 2025. The Company also incurred costs in 2022 of $2.6 million. On pages 31 and 32 of his direct testimony, Mr. Joyce discusses the Company's

[44] Exhibit AG-19 includes WP-TKJ-5, page 2, and DR AG-CE-0310.

plan to retire the Riverside gas storage field and replace this source of gas for nearby customers fed directly from the field with new pipelines and new regulating and gate stations. According to Mr. Joyce, the field has low working gas storage capacity, and the underground storage formation contains hydrogen sulfide which requires that the gas withdrawn from the field be processed.

Although Mr. Joyce does not provide the total cost for this project in his brief testimony, in response to discovery the Company reported that from start of the project to completion the total cost of the project has been forecasted at $127.8 million, including the cost for removal of existing facilities.[45] This estimate is based on a cost analysis of alternatives prepared in May 2021 and at this point may be stale and the total cost likely understated. The proposed Option 2 entails the construction of a mainline and lateral lines to replace existing pipelines, new city gate and regulating stations, retirement of storage facilities, wells, gas conditioning equipment, and retirement of 3 city gate stations. The May 2021 analysis and discovery response AG-CE-0314 in this rate case are included in Exhibit AG-23.

Q. WHAT IS YOUR ASSESSMENT OF THE RIVERSIDE STORAGE FIELD RETIREMENT PROJECT?

A. At a cost of $127.8 million and likely higher, the course of action chosen by the Company entails a very costly project that is not warranted at this time. In discovery in Case No. U-

[45] Case No. U-21308 DR AG-CE-0434 with Attachments.

21308, the Attorney General asked the Company to explain what the main driver was for undertaking this project at this time given that the reasons identified to justify the project, such as the storage field low working capacity, connection with three city gates limiting storage withdrawal volumes, and hydrogen sulfide in the gas have existed for years. In its response, the Company provided general statements and pointed to its goal to retire the storage field under the Natural Gas Delivery Plan (NGDP).[46] The Company's response lacked the level of detail requested and it remains unclear why the project needs to be done now at such a high cost. Furthermore, the NGDP should be used as a general guide and not as a mandatory program that should be followed without fail.

On page 5 of the analysis of alternative options considered by the Company (Ex. AG-23 Attachment 2), Option 6 is a lower cost alternative at $54.6 million. This lower cost option would entail recoating the Riverside mainline with replacement in 20 years, replacement of the 80W line, rebuilding of the McBain city gate, and deferring replacement of the Forward-Falmouth lateral line for 20 years. This is a viable option.

Although Option 6 has a significant lower cost, in the evaluation of options in the May 2021 project analysis, it lost out to Option 2 because of lower scores for subjective criteria about safety, reliability and cleanness (Page 11 of May 2021 analysis). These subjective criteria were heavily weighted against Option 6 resulting in a total point score much lower than Option 2. In discovery, the Company was asked to explain how it assigned the respective scores for the non-cost items. The response simply repeats general concerns

[46] Exhibit AG-24 includes DR U-21308 AG-CE-0562.

with safety, reliability, and gas emission. There was no sound methodology used to the assigned relative values. Also, it is inconceivable that Option 2 would be assigned a score of 2.2 for its cost relative to the 2.6 score assigned to Option 6 when the cost for Option 2 is nearly twice the cost of Option 6. It is evident that the scorecard evaluation performed by the Company was not sound and was skewed to favor Option 2.

Q. HAVE THERE BEEN RECENT DEVELOPMENTS WHICH CLOUD THE FUTURE PLANS FOR THIS PROJECT?

A. Yes. In response a discovery question from the Commission Staff, the Company stated that it has concluded its evaluation about selling the storage field to a third party and is actively pursuing such a sale of the field.[47] This development puts the entire project and the spending plans in a state of uncertainty. This event plus my conclusion that the course of action chosen by the Company was not the most reasonable and appropriate given the lower cost and workable alternative available in Option 6 require that the entire project be re-evaluated and deferred.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission reject all capital expenditures presented in this rate case for the Riverside Gas Storage Retirement project. This entails removal of capital expenditures of $33,318,000 for the 9 months ending September 2024, and $37,067,000

[47] Exhibit AG-23 includes DR ST-CE-0079.

for the 12 months ending September 2025, as shown on page 5 of WP-TJK-6 (Exhibit AG-23).

<u>6. Lyon 29/34 (Northville Storage) Dehydration</u>

Q. PLEASE DISCUSS THE NORTHVILLE STORAGE GAS DEHYDRATION PROJECT.

A. On line 10 of page 2 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company shows the forecasted capital expenditures for the Northville Storage Field at $1.4 million for 2023, $9.3 million for the 9 months ending September 2024, and $22.3 million for the 12 months ending September 2025. Beginning on page 33 of his direct testimony, Mr. Joyce discusses the Lyon 29/34 project which entails the construction of a dehydration unit. The Company seems concerned with the moisture content of the gas withdrawn from the Northville gas storage field not meeting the 7bl. per Mcf required for delivery to customers. The Lyon 29/34 is a metering station feeding gas to a transmission line and the Northville storage compressor station. To resolve the occasional excessive moisture content of the gas stream, originating from the Northville storage field during the gas withdrawal period, the Company wants to install a gas purification/dehydration facility near the Northville compressor station.

Although in his testimony, Mr. Joyce does not identify the cost of this project, in response to discovery, the Company provided a schedule that shows the total cost from 2022 to the end of 2028 at $62.5 million.[48] WP-TJK-6 shows capital expenditures of $1,373,000 for 2023, $9,273,000 for the 9 months ending September 2024, and $22,191,000 for the 12 months ending September 2025.[49]

Q. WHAT IS YOUR ASSESSMENT OF THE NORTHVILLE STORAGE GAS DEHYDRATION PROJECT?

A. The project is still in the early stages of development. The cost of the project is significantly large and given the infrequent occurrence of moisture issues with the gas stream from the Northville storage fields, it should be analyzed further for a more cost-effective solution.

In response to AG-CE-0315, the Company identified a few incidents of excessive moisture in the gas stream between 2019 and 2021.[50] However, beginning in 2021, the Company changed the utilization of the Northville storage fields to be a peaking storage facility to be used only during days in the winter when customer gas demand reaches near peak demand. Therefore, like in 2021, in future years no gas withdrawals from the fields may happen or may only occur on very few select days. In fact, the Company withdrew gas from the field only once in 2021 in March and perhaps once in 2022, and none in 2023. It does not seem cost effective to build a high-cost facility that will sit idle and not be utilized other than on rare occasions.

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[48] Exhibit AG-25 includes DR AG-CE-0315 with ATT 1.
[49] Id. includes WP-TJK-6.
[50] Id. includes DR AG-CE-0315 ATT 3.

In discovery request AG-CE-0316, the Attorney General asked the Company whether it had performed an analysis to see if gas withdrawn occasionally from the Northville storage fields with higher moisture content could be blended with drier gas from other sources as an effective solution to prevent a moisture problem before delivering the gas to customers. In response, the Company stated that it had not performed such an analysis because it does not recognize gas blending as a competent means for ensuring gas quality. Although such a position makes sense on a wider scale, on the rare occasions of gas withdrawals from the Northville storage fields and in limited volumes, it can be an effective strategy. DTE Gas utilizes gas blending temporarily when it experiences failures with its gas dehydrating equipment at or near its gas storage fields with no ill effect on customers' gas burning equipment.

Attachment 4 to DR AG-CE-0315 shows that the volume of gas withdrawn on those unusual occasions in 2021 and 2024 represented 0.0009% and 0.038% of the Company's total system sendout on those days. This is an infinitesimal percentage that should not pose a problem with the Company delivering natural gas to customers with high moisture content above the 7 lb. per Mcf standard.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The Lyon 29/34 Northville Gas Dehydration project is not a cost-effective solution for an investment exceeding $62 million on a facility that would be rarely used.

Therefore, I recommend that the Commission remove the capital expenditure of $1,373,000 for 2023, $9,373,000 for the 9 months ending September 2024, and $22,191,000 for the 12 months ending September 2025.

7. Well Rehabilitation Program

Q. PLEASE IDENTIFY THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR THE WELL REHABILITATION PROGRAM.

A. On page 2, line 15 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company forecasted capital expenditures to rehabilitate storage wells of $35.5 million for 2023, $23.9 million for the 9 months ending September 2024, and $33.9 million for the 12 months ending September 2025. Mr. Joyce discusses the capital expenditures for well rehabilitation beginning on page 36 of his direct testimony.

In response to discovery, the Company provided an updated Exhibit A-84 with actual program expenditures from 2017 to 2023 and forecasted expenditures for 2024 and future years. Exhibit AG-26 includes the discovery response and attachment with the program's capital expenditures. The yearly schedule of expenditures shows a ramp up of expenditures from $14.9 million in 2017 to a peak of $36.8 million in 2022 and then a decline to $30.8 million in 2023. Although the total cost has risen, the number of wells rehabilitated declined from 133 in 2017 to 73 in 2023. The Company attributes the higher cost in 2018 and future years to an initial lag in certain expenditures due to performance testing requirements done after the first year of operation of the rehabilitated wells. The average cost to rehabilitate a well in the three years from 2021 to 2023 was $461,221.

For 2024, the Company forecasted $29,592,000 to rehab 58 wells at an average cost of $510,211 per well. This cost per well is 11% higher than the average cost for the prior three years. For 2025, the Company shows forecasted capital expenditures of $33,030,000 to rehab 68 wells. The cost per well for 2025 declines to $485,737. On page 36 of his direct testimony, Company witness Timothy Joyce states that the forecasted expenditures were based on specific work scopes developed by the engineering department and shown in Exhibit A-84 (TKJ-6). However, there is no direct link or calculation provided in Exhibit A-84 that supports the forecasted capital expenditures for 2024 and 2025. Those forecasted expenditures remain unsupported.

Using the average cost per well of $461,221 for the three years from 2021 to 2023 and applying an inflation factor of 2.6%, I arrived at an average cost per well of $473,212 for 2024. Multiplying this unit cost by the 58 wells forecasted to be completed in 2024, I forecasted capital expenditures for the year of $27,446,000 and $20,584,000 for the 9 months ending 2024. This amount is $3,289,000 lower than the Company's forecast of $23,873,000 for the 9 months period.

For 2025, I calculated a cost per well of $483,623 using the inflation rate of 2.2% on the 2024 inflation adjusted cost of $473,212. By multiplying the $483,623 average cost for the 68 units forecasted for 2025, I determined the total cost for the year at $32,886,000. For the 12 months ending September 2025, the forecasted amount is $31,526,000 using nine months from 2025 and three months from the 2024 forecasted cost. This amount is $1,326,000 lower than the Company forecasted amount of $32,852,000.

Therefore, I recommend that the Commission remove $3,289,000 for the 9 months ending September 2024 and $1,326,000 from the 12 months ending September 2025 from the Company's forecasted capital expenditures.

8. Gas Compression & Storage – 2023 Capital Expenditures

In discovery, the Company was asked to provide the actual amount spent on all Gas Compression and Storage capital programs during 2023. In response the Company reported that it spent $113,115,000 in 2023.[51] In Exhibit A-12 (TKJ-5), Schedule B-5.7, page 1, the Company shows that it included $121,866,000 of capital expenditures for 2023 in this rate case. The difference is an underspent amount of $9,229,000. This amount should be removed from rate base in this rate case. The Company did not incur this cost and it is not fair or reasonable for the Company to earn a return and recover depreciation expense for costs in it did not incur.

Therefore, I recommend that the Commission remove the 2023 underspent amount of $9,229,000 from rate base in this rate case.

D. Information Technology (IT) - Capital Expenditures

Information Technology projects are often presented by both the Company witness in the operating function that requires and sponsors the project and from the IT witness

[51] Exhibit AG-27 includes DR ST-CE-0330.

responsible to develop and implement the project, and who is also responsible for the cost of the project. Therefore, reference is often made to testimony, exhibits and discovery responses from multiple witnesses.

1. IT Projects in Investment Planning

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE CAPITAL EXPENDITURES FOR IT PROJECTS IN THE INVESTMENT PLANNING PHASE.

A. In Exhibit A-20, the Company presents each of the IT projects under development. In discovery, the Attorney General asked the Company to identify the total cost of projects of $3 million or higher from inception to completion and report the phases and timeline of the projects with the current phase of the project. In response, the Company identified 18 projects that met the threshold cost level. For two of those projects, the Company disclosed that they are currently in the investment planning phase. The two projects are: Asset Accounting Upgrade and Customer Order Service Tracker. System requirements for those projects have not yet been defined.[52]

These projects span both the gas and electric businesses of the Company. For the Asset Accounting System Upgrade, the Company forecasted $446,063 for the gas business to be spent in 2025. Of this amount, $335,000 is included in the projected test year ending September 2025. For the Customer Order Service Tracker, the Company assigned $1,142,010 of capital expenditures to the gas business to be spent in 2025. Of this amount,

[52] Exhibit AG-28 includes DR AG-CE-0397 with attachments.

$857,000 is included in projected test year ($685,000 after the Company's ROM adjustment).

Both of these projects are in the early phase of development. It is premature to include the cost of these projects in rate base at this time given the uncertainty of whether the projects will proceed to completion, or the costs will be incurred as forecasted. Therefore, I recommend that the Commission remove the forecasted capital expenditures of $1,020,000 for the 12 months ending September 2025. Related to the capital spending for the two projects, the Company also forecasted O&M expense of $314,000 for 2025, of which $236,000 falls in the projected test year. In my testimony below on O&M expense I will remove this amount from the Company's forecasted O&M expenses for the project test year.

2. Customer Order Request Portal

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE CAPITAL EXPENDITURES FOR THE CUSTOMER WORK REQUEST PORTAL IT PROJECT.

A. On pages 11 through 15 of his direct testimony, Mr. Steven McLean describes two IT projects related to customer service. One of the projects is the Customer Service Order tracker discussed above, for which I proposed the Commission disallow the forecasted capital expenditures for the projected test year as being premature. The second project is the Customer Work Request Portal. According to Mr. McLean's testimony, the purpose for this project is for customers and builders to submit new service requests through the website instead of filing a form application. The total estimated cost of the project is approximately $1.9 million, of which $581,243 has been assigned to the gas business in 2025. Of this amount, $436,000 falls in the projected test year ($349,000 after the Company's ROM adjustment). In addition, the Company forecasted O&M expense of $159,389 during the 2015 development phase, of which $119,000 is included in the projected test year.

In discovery, the Attorney General asked the Company to provide the number of calls or requests that the Company receives annually for new service work and the cost/benefit analysis that justifies undertaking both projects. In response, the Company reported that it receives approximately 8,000 requests a year for new service connections. The Company has more than 2 million gas and electric customers. In the response, the Company could not identify any cost savings from this work efficiency project, other than some intangible customer convenience benefits. The responses and project cost analysis showing no identified financial benefits are included in Exhibit AG-29.

Q. WHAT IS YOUR ASSESSMENT OF THE CUSTOMER WORK REQUEST WEB PORTAL?

A. The Company has not adequately justified that there are sufficient financial and non-financial benefits to undertake this project given the relatively small number of new service orders received each year. The capital that would be spent on this project would be better deployed to replace deteriorating gas distribution infrastructure. Therefore, I propose that the Commission remove $349,000 of capital expenditures from the projected test year and the related $119,000 from O&M expense.

3. Gas Compression Historian System

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE CAPITAL EXPENDITURES FOR THE GAS COMPRESSION HISTORIAN PROJECT.

A. On page 54 of his direct testimony, Mr. Joyce proposes to implement the Gas Compression Historian system to store, retrieve, and analyze data pertaining to gas storage facilities. The projected test year capital cost is $1,661,000 ($1,329,000 after the ROM adjustment) and the O&M expense is $133,000. The total cost of the project to completion is forecasted at $2.2 million.[53] This project also was proposed in the prior rate case U-21308 and apparently delayed.

In discovery in Case No. U-21308, the Attorney General asked the Company to explain more thoroughly what functions the new system will perform and to provide a cost/benefit analysis. In its response, the Company elaborated further on Mr. Joyce's direct testimony and provided the Net Present Value (NPV) calculation of costs.[54] The financial analysis in the NPV schedules does not show any cost savings to economically justify the project. Based on the description of the project in Mr. Joyce's testimony and discovery response, one of the main drivers for implementation of the project is increased efficiencies in storing, retrieving, and analyzing data. However, from the cost benefit analysis, it appears that the Company is not expecting any significant cost savings from the new system. Therefore, it is not an economically viable project.

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[53] U-21308 DR AG-CE-0441.
[54] U-2108 DR AG-CE-0575.

In response to discovery in both Case U-21308 and in this rate case, the Company also stated that the project is currently in the investment planning stage indicating that not much work has been done to assess and match system requirements to the prospective system to be acquired.[55] Given the preliminary stage of developed and the lack of an economic case for the project, I recommend that the Commission remove $1,329,000 of capital expenditures from the projected test year and $133,000 from O&M expense.

4. Gas Facilities Tracking and Traceability Project

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE CAPITAL EXPENDITURES FOR THE GAS FACILITIES TRACKING AND TRACEABILITY SYSTEM.

A. On page 75 of his direct testimony, Mr. Warriner discusses the Tracking and Traceability system project with forecasted capital expenditures of $1,328,438 and $500,378 of O&M expense in the projected test year. The project is intended to develop a system to identify, track, and trace the Company's gas facilities from pipes to fittings and other components.

In discovery the Attorney General asked the Company to provide the project cost/benefit analysis and the project development phases including the current phase of the project. In response, the Company provided a copy of the project cost/benefit analysis showing that the estimated cost of the project is in excess of $15 million to be developed over the 2025 to 2027 timeframe. No cost savings or financial benefits were identified for the project.

[55] Exhibit AG-30 includes DR AG-CE-0324.

The Company also disclosed that the project is currently in the investment planning phase.[56]

Q. WHAT IS YOUR ASSESSMENT OF THE TRACKING AND TRACEABILITY PROJECT?

A. Aside from the fact the project is not economically justified, the project is in the early stage of development being in the investment planning phase. It appears that not much work has been done to assess and match system requirements to the prospective system to be acquired. Given the preliminary stage of developed and the lack of an economic case for the project, I recommend that the Commission remove $1,328,000 of capital expenditures from the projected test year and $500,000 from O&M expense.

5. IT Projects – 2023 Capital Expenditures

In discovery the Company was asked to provide the actual amount spent on all IT capital programs during 2023. In response the Company reported that it spent $21,223,000 in 2023.[57] In Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, the Company shows that it included $23,069,000 of capital expenditures for 2023 in this rate case. The difference is an underspent amount of $1,846,000. This amount should be removed from rate base in this rate case. The Company did not incur this cost and it is not fair or reasonable for the Company to earn a return and recover depreciation expense for costs in it did not incur.

[56] Exhibit AG-31 includes DR AG-CE-0221 with related attachments.
[57] Exhibit AG-32 includes DR AG-CE-0396 with attachment.

Therefore, I recommend that the Commission remove the 2023 underspent amount of $1,846,000 from rate base in this rate case.

E. Operations Support - Capital Expenditures

In Exhibit A-12 (QAG-1), Schedule B-5.6, the Company forecasted capital expenditures for Asset Preservation of $21.2 million for 2023, $12.3 million for the 9 months ending September 2024, and $26.1 million for the 12 months ending September 2025. In comparison, the Company incurred capital expenditures of $24.9 million in 2022. Exhibit A-71 provides further details of the areas where the capital spending is forecasted to occur.

A large portion of the capital spending in the projected periods pertains to the replacement and renovation of three customer service centers in Lansing, Kalamazoo, and Hastings. I will discuss each of these projects separately.

Also, included in the capital expenditures for the 2022 and 2023 periods are projects for the EIRP Building Construction projects, which I will also discuss below.

1. New Service Centers

On lines 17, 18 and 22 of Exhibit A-71 (QAG-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 2023 is $3,024,000. For the 9 months ending September 2024, the total forecasted amount is $6,269,000. For the 12 months ending September 2025, the forecasted capital expenditures are $16,118,000. Actual capital expenditures for the three projects in 2022 were $417,000.

Mr. Quentin Guinn discusses the three service centers beginning on page 18 of his direct testimony. The three centers serve both gas and electric customers, and the costs are allocated proportionally to each business. There has been a long history about the delay in the construction of the three service centers and the Commission decisions on the recovery of related costs in prior rate case. An historical perspective is in order. In Case No. U-20963, the Company forecasted capital expenditures for 2022 of $34,775,000 for construction and renovation of the three service centers. In the electric rate case in 2022 (Case No. U-21224) the Company forecasted to spend only a small fraction of that amount at $1,591,000. In Case U-20963, the Commission approved the $34,775,000 in proposed spending contrary to my recommendations against it. In Case No. U-21224, I addresses the same issues with the three service centers and, in response to discovery, the Company stated that not much had changed since I filed testimony in that case in early 2022. In the most recent electric rate case U-21389, the Commission adopted the Administrative Law Judge recommendation to disallow all forecasted capital expenditures proposed by the Company for the three service centers. In the March 1, 2024, the Commission stated:

> The Commission adopts the findings and recommendations of the ALJ. As the Attorney General and the ALJ point out, previously approved amounts were not spent, and meanwhile the costs, timeframes, and scope of work have changed for all of these projects. While the Commission is not rejecting Consumers' long-term plans for the service center rebuilds, the projects presented on this record do not appear to be ready for rate base treatment.

Not much has changes since the March 1, 2024, Commission order.

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

A. In response to discovery, the Company provide an implementation timeline for the Lansing Service Center and the actual costs incurred in 2023 versus forecasted costs. Although the Company shows that some construction work has been completed in 2023, the actual costs fell short of the forecasted capital expenditures by 32%. For the total project, the Company had forecasted to spend $4.8 million in 2023 and only spent $3.3 million.[58] It appears that the project is proceeding at a slower pace than forecasted. Given the prior history with delays on this project, I propose that the forecasted costs for the projected period be reduced by 30%. Therefore, I recommend that the Commission remove capital expenditures of $1,057,000 from the 9 months ending September 2024 ($3,105,000 x 30%) and $2,088,000 from the 12 months ending September 2025 ($6,959,000 x 30%).

With regard to the Hastings Service Center, there was not much going on in 2023 with only $9,000 spent for the year. In response to discovery, the Company reported in 2024 it will pursue purchase of the land on which to build the service center and the project plan has been revised.[59] It seems certain that the capital expenditures will not materialize as forecasted in this rate case. Therefore, I recommend that the Commission remove the forecasted capital expenditures of $212,000 for the 9 months ending September 2024 and the $2,556,000 for the 12 months ending September 2025.

The Kalamazoo Service Center is also proceeding on a slow track. The Company had forecasted spending about $1.3 million in project engineering costs in 2023 and actually

[58] Exhibit AG-33 includes DR AG-CE-0296 with ATT 1. See also the table on page 26 of Mr. Guinn's direct testimony.
[59] Exhibit AG-34 includes DRs AG-CE-029 and 0299.

spent $368,000.[60] The underspent amount is a shortfall of 72%. The project timeline shows construction beginning in late 2024 and into 2025.[61] However, given prior delays with this project, that schedule cannot be relied on. I propose that the forecast capital be reduced by 70%. Therefore, I recommend that the Commission remove capital expenditures of $2,066,000 for the 9 months ending September 2024 ($2,962,000 x 70%) and $4,622,000 for the 12 months ending September 2025 ($6,603,000 x 70%).

In total, for the three service centers, I recommend that the Commission remove capital expenditures of $3,335,000 for the 9 months ending September 2024, and $9,266,000 for the 12 months ending September 2025.

2. EIRP Support Facilities

Q. PLEASE DISCUSS THE COMPANY'S CAPITAL EXPENDITURES FOR EIRP SUPPORT FACILITIES AND RELATED OPERATING LEASES.

A. On pages 33 and 34 of his direct testimony, Mr. Guinn briefly discusses that the Company leased six facilities to store materials and function as a hub for employees that support the EIRP construction activities. Exhibit A-71 shows that the Company spent $1,421,000 on these facilities in 2022 and planned to spend an additional $4,499,000 in 2023. From the limited information provided in Mr. Guinn's testimony, it appears that the Company had to perform some construction work at the six facilities during both 2022 and 2023.

[60] Exhibit AG-35 includes DR AG-CE-302 with actual costs. See also page 40 of Guinn's direct testimony.
[61] Id. includes DR AG-CE-0303.

In response to discovery, the Company provided additional information on construction work performed at the facilities and the lease payments made at five of the six facilities. The information provided in response to DR AG-CE-0300 shows that only five facilities are being leased and the sixth facility is owed by Consumers Energy.[62] Based on the information provided by the Company, I calculated the lease payments included in O&M expense for the projected test year at $1,061,000.

Q. DID THE COMPANY INCLUDE THE 2022 AND 2023 FORECASTED CAPITAL EXPENDITURES IN CASE NO U-21308 OR IN OTHER PRIOR RATE CASES?

A. No. This rate case is the first time that the Company showed capital expenditures for EIRP support facilities. My review of the testimony and exhibits sponsored by Mr. Guinn in Case No. U-21308 shows no presentation or discussion of capital expenditures and lease payments to be paid for facilities to support EIRP construction activities. To my knowledge, no other witness in this rate case or Case U-21308 proposed and supported the necessity, reasonableness, and prudency of the capital expenditures included in Exhibit A-71 and the and the lease payments in this rate case.

Furthermore, in discovery, the Attorney General asked the Company to explain why the EIRP required the storage space and facilities now given that the program has been in existence for nearly 10 years without requiring the storage space and facilities. The

[62] Exhibit AG-36 include DR AG-CE-300 and 301 with related attachments.

response provided does not answer the question and refers again to the facilities themselves. The costs remain unsupported.

Therefore, I recommend that the Commission remove the capital expenditures of $1,421,000 for 2022 and the $4,499,000 for 2023 from rate base in this rate case. Additionally, I recommend that the Commission remove the lease payments of $1,061,000 from O&M expense in the projected test year.

3. Facilities Projects – 2023 Capital Expenditures

In discovery the Company was asked to provide the actual amount spent on all Operations Support capital programs during 2023. In response the Company reported that it spent $16,032,000 in 2023.[63] In Exhibit A-12 (SHB-4), Schedule B-5.8, page 1, the Company shows that it included $21,852,000 of capital expenditures for 2023 in this rate case. The difference is an underspent amount of $5,820,000. This amount is before the $4,499,000 disallowance for the EIRP support facilities for 2023, which I recommended above. Therefore, net of this disallowance the amount that should be removed from rate base in this rate case is $1,321,000. However, if the Commission does not accept the $4,499,000 disallowance, the amount that should be removed from rate base is $5,820,000. The Company did not incur this cost and it is not fair or reasonable for the Company to earn a return and recover depreciation expense for costs in it did not incur.

[63] Exhibit AG-37 includes DR AG-CE-0307 Revised with attachment.

F. Security Operations - Capital Expenditures

In Exhibit A-12 (BSB-1), Schedule B-5.2, the Company forecasted capital expenditures for Security of $6.0 million for 2023, $4.1 million for the 9 months ending September 2024, and $4.6 million for the 12 months ending September 2025. In discovery, the Attorney General asked the Company to provide further details on the projects underlying the forecasted capital expenditures, including the total cost of the project and the timeline and phases of development, including the phase that the project is currently in.

In response the Company identified six projects. Three of those projects are still in the planning stage. Those projects are (1) the Badge Reader, Lock and Key Management system, (2) the Savynt Critical Facility Structure, and (3) the Security Threat Intelligent Tool. The combined cost for these projects is $18,51,000 for 2024, and $2,282,000 for 2025.[64] The amounts pertaining to the 9 months ending September 2024 and he 12 months ending September 2025 are $1,388,000 and $2,174,000, respectively. Additionally, the Company has included $196,000 of O&M expense in the projected test year.

The three projects are still in the early phase of development. It is premature to include the cost of these projects in rate base at this time given the uncertainty of whether the projects will proceed to completion, or the costs will be incurred as forecasted. Therefore, I recommend that the Commission remove the forecasted capital expenditures of $1,388,000 for the 9 months ending September 2024, and $2,174,000 for the 12 months

[64] Exhibit AG-38 includes DR AG-0382.

ending September 2025. Additionally, the Commission should remove $196,000 of O&M expense from the projected test year.

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)
Distribution Plant	$ 174.9
Transmission Plant	48.2
Gas Storage & Compression	157.3
Information Technology	5.9
Operations Support & Security	23.3
Total	**$ 409.7**

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 $409.7 million and reduce average rate base by $385.3 million, including an adjustment to working capital of $104.6 million, as shown in Exhibit AG-39. The resulting effect of the lower rate base from the reduction in capital expenditures is a reduction in the revenue deficiency of $31.0 million.

V. Depreciation Expense

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

A. In Exhibit AG-39, I 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 $8.1 million. I recommend that the Commission reduce the Company's depreciation expense by this amount for the projected test year.

VI. Property Tax Expense

Q. PLEASE DISCUSS THE PROPERTY TAX EXPENSE ADJUSTMENT THAT YOU PROPOSE.

A. In Exhibit AG-39, I identified the adjustments to be made to the Company's proposed capital expenditures. Those reductions lower the amount of property tax expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in property tax expense of $2.8 million. I recommend that the Commission reduce the Company's property tax expense by this amount for the projected test year.

VII. Working Capital

Q. THE COMPANY HAS PROPOSED $1.515 BILLION OF WORKING CAPITAL IN THIS CASE.[65] DO YOU AGREE WITH THIS LEVEL OF WORKING CAPITAL?

A. No. I recommend four changes in the Working Capital level, which total $104.6 million, and reduce the amount of Working Capital to $1.410 billion. The first change is to reduce the Company's gas storage inventory by $66.7 million due to lower gas prices. The second change is a reduction in Accounts Payable of $11.4 million which increases Working Capital. This second item, as explained below, is interrelated to the change in gas inventory noted above. The third change is a $30.1 million reduction in the level of Accounts Receivable due to substantially lower revenues in this case for the projected test year compared to 2022. The fourth change is to Accrued Taxes which reduces Working Capital by $19.2 million due to the Company's failure to properly forecast this liability for the projected test year. These changes are shown and summarized in Exhibit AG-40.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THAT THE COMPANY'S GAS STORAGE INVENTORY COST WILL BE LOWER BY $66.7 MILLION.

A. Company witness Joyce discusses the cost of gas and the cost of inventory gas on pages 20 and 21 of his testimony and points out that his estimated cost rate for inventory gas is $3.571 per Mcf. This estimate of gas prices and the Company's inventory value was

[65] Exhibit A-12 (HLR-34), Schedule B4

developed in September 2023 based on the NYMEX future gas prices for the projected test year at that point in time.

Recognizing that natural gas prices have fallen substantially since September 2023, the Attorney General and the Commission Staff asked the Company to provide more recent information on gas prices, the forecasted cost of gas, and the inventory value for the projected test year. The Company's discovery response shows an updated cost of gas held in inventory for the projected test year of $3.03 per Mcf, which is lower by $0.667 per Mcf or an 18% reduction from the Company's rate case filing. The attachments to the discovery response also shows a revised gas inventory cost of $396.8 million.[66] This amount is $66.7 million lower than the original estimate of $463.5 million. The $463.5 million had been included in the Company's Working Capital calculation in Exhibit A-12, Schedule B4. I recommend that the Commission accept the more recent inventory value forecast which reduces Working Capital for the projected test year by $66.7 million.

Q. PLEASE EXPLAIN HOW YOU ARRIVED AT YOUR LOWER AMOUNT OF ACCOUNTS PAYABLE OF $11.4 MILLION, WHICH INCREASES WORKING CAPITAL

A. Changes in gas purchases due to higher or lower gas prices have an impact on both the cost of the Company's inventory value and Accounts Payable from gas purchases. Witness Rayl performed an analysis and determined a 17.07% relationship between gas purchases

[66] Exhibit AG-42 includes DR SA-CE-101 and related attachments.

in Accounts Payable and the cost of gas inventory. Therefore, in Exhibit A-12 (HLR-34). Schedule B4, she increased Accounts Payable by $46.3 million in the rate case filing, or 17.07% of the inventory change, based on the higher gas prices forecasted in September 2023.

Now that Mr. Joyce has provided a revised estimate for the cost of inventory gas which is reduced by $66.7 million, I used this same ratio to adjust Accounts Payable downward by $11.4 million ($66.7 million x 17.07%). The reduction in Accounts Payable increases the projected test year working capital by $11.4 million.

Q. PLEASE EXPLAIN YOUR CHANGE TO ACCOUNTS RECEIVABLE WHICH REDUCES WORKING CAPITAL.

A. In Exhibit A-13, Schedule C3, the Company shows forecasted revenues of $2.4 billion for the projected test year, which are substantially lower than the historical revenues of $2.7 billion. However, line 2 of Exhibit A-12, Schedule B-4, shows Accounts and Notes Receivable increasing by $6.3 million between the historical and projected test year. The increase in the Accounts and Notes Receivable is inconsistent with the decrease in revenues because revenues drive the balance of Accounts Receivable.

On line 1 of Exhibit AG-41, I show the Company's 2022 revenues and Accounts Receivable. On lines 3 and 4, I calculated the decline in revenues between the 2022 historic test year and the projected test year of $317.5 million, as sponsored by the Company, plus the $148 million change in revenues due to the lower cost of gas as discussed above. These changes total to $465 million, which represent a decline of 17.1% from 2022 revenues. By applying the 17.1% to the 2022 average accounts receivable balance, I calculated Accounts Receivable for the projected test year at $115.2 million. This amount is $30.1 million lower than the Company's forecasted amount.

Therefore, I recommend that the Commission adopt my adjustment and reduce working capital for lower accounts receivable by $30.1 million.

Q. PLEASE EXPLAIN YOUR PROPOSED CHANGE TO ACCRUED TAXES.

A. Exhibit A-12 (HLR-34) reduces Accrued Taxes from $170.5 million for the 13 months ended June 2023 period to $151.3 million in the projected test year for a decline of $19.2 million. Ms. Rayl, who sponsors this exhibit, provides no explanation in her testimony for this change.

The Company's forecasted Accrued Taxes are lower in the projected test period than they were in the 2022 and in the June 2023 historical periods. In discovery, the Attorney General asked the Company to explain the decline in Accrued Taxes and requested certain historical information. In response, the Company stated that they had not adjusted the Accrued Taxes for the projected test year to include the additional income taxes that will result from the requested rate relief in this rate case.[67] The Company's failure to properly adjust Accrued Taxes for the additional taxes it will pay as a result of the additional income

[67] Exhibit AG-43 includes DR AG-CE-155(b).

it will earn from the revenue received from the rate increase is a major flaw that needs to be corrected.

As discussed above, the Company's projection is based on an incomplete assumption and an alternative approach is warranted. Accordingly, I used the Company's historical June 2023 average balance, which is $19.2 million higher than the Company's forecasted test year balance. This balance for Accrued Taxes is more representative of the projected test year balance than the Company's projected balance. Therefore, I recommend that the Commission adopt the actual 13-month average balance for Accrued Taxes as of June 2023, which reduces the Company's forecasted working capital by $19.2 million for the projected test year.

In summary, the changes discussed above result in a lower working capital amount of $104.6 million. I recommend that the Commission adopt this reduction to the working capital amount forecasted by the Company for the projected test year.

VIII. Capital Structure and Cost of Capital

A. CAPITAL STRUCTURE

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

A. I recommend that the capital structure shown on page 1 of Exhibit AG-44 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 September 2025. The capital balances in this exhibit reflect the amounts shown in Exhibit A-14 (MRB-1), Schedule D1, with an adjustment to rebalance the capital structure. The long-term debt component in Exhibit AG-44 has been increased by $353 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 $353 MILLION AND OFFSET THIS CHANGE WITH LOWER COMMON EQUITY OF $353 MILLION?**

A. The Company has proposed a permanent capital structure with a common equity component of 51.50%. It is higher than the common equity ratio of 50.75% from the settlement in the Company's last gas rate case, Case No. U-21308. This level of common equity also exceeds the 50.02% level recently approved by the Commission in the Company's last fully contested electric rate case, Case No. U-21389 on March 1, 2024.[68] The capital structure in this rate case should similarly mirror the common equity ratio approved on March 1, 2024, which I have rounded down to 50%. As discussed in Case No. U-21389, there are several factors that clearly support a 50% common equity level.

These factors include (1) the Commission's consistent directive in the Company's prior electric and gas rate cases, which stated that a 50/50 capital structure is desirable and

[68] Case U-21389 decision of March 1, 2024.

appropriate to ensure reduced costs to customers and maintain the Company's strong financial position, unless the Company can demonstrate that a higher ratio is justified; (2) The Company's strong cash flow to debt coverage ratio and credit ratings; (3) the Company's common equity capital contributions by the parent company, albeit often funded with long term debt issued at the parent company level; (3) the favorable regulatory environment in Michigan supported by historical returns on common equity above industry averages and in the top tier of the Company's peer group; 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 46%.[69]

Q. WHAT POSITION DID THE COMMISSION TAKE IN THE COMPANY'S MOST RECENTLY CONTESTED RATE CASE ON CAPITAL STRUCTURE?

A. In the recent March 1, 2024 order in Case No. U-21389, the Commission decided to set the common equity ratio at 50.02%, as recommended by the MPSC Staff and supported by the Attorney General and by ABATE who recommended a 50% common equity ratio be adopted. On page 129 of the order, the Commission stated the following:

> The Commission finds that the record supports the adoption of a balanced capital structure. The Commission is unpersuaded by the company's arguments that the adoption of a balanced capital structure will degrade Consumers' credit metrics. The adoption of a balanced capital structure results in a modest reduction in the authorized equity layer, given Consumers' agreement to a 50.75% equity layer in case U-21224. *See,* January 19 order, Exhibit A, p. 4. The Commission also finds that the ALJ did not ignore or improperly reject the company's evidence as claimed by Consumers in exceptions. *See*, PFD, pp. 217-261.

[69] Exhibit AG-47 shows that the peer group average equity ratio for each peer company and in total which is 45.7%.

> Notwithstanding the above, the Commission finds that the most reasonable and prudent approach to achieving this goal was set forth by the Staff. Therefore, the Commission finds that a common equity layer on $10.880 billion should be adopted, which equates to a 50.02% equity ratio in the permanent capital structure. *See,* 5 TR 3623, Exhibit S-4, Schedule D-1, line 3. This equity balance is a slight reduction to the 50.75% equity layer agreed to by the parties in Case U-21224, which is consistent with prior Commission directives to gradually achieve a balanced capital structure.

Mr. Bleckman has not provided any new evidence or persuasive arguments in this rate case as to why the Commission should veer from its stated goal of a 50/50 debt/equity capital structure for the Company.

Q. ON PAGE 18 OF HIS TESTIMONY, MR. BLECKMAN POINTS TO THE MOODY'S DOWNGRADE OF CONSUMERS ENERGY IN MAY 2021. WHAT IS YOUR ASSESSMENT?

A. From 2017 to 2020, Moody's Investor's Service (Moody's) had assigned a senior secured debt rating of "Aa3", which was in the double "A" category, while both Fitch Investor Service (Fitch) and Standard & Poor's (S&P) rated Consumers Energy in the "single A" category. In May 2021, Moody's lowered its credit rating to "A1" which is at the top of the "A" category and equivalent to an "A+" rating by Fitch and just above the rating of S&P. Fitch is currently rating the Company senior secured debt at "A+" and S&P has a rating of "A". Thus, after the downgrade, the Moody's credit rating is either at par or still above the credit ratings of the other two rating agencies.

As recently as 2016, the Company's Moody's credit rating was "A1" which further indicates that the rating agency had temporarily increased the credit rating for the

Company's senior secured debt.[70] Therefore, it is evident that the previous Moody's rating was above the other rating agencies' views of the Company's credit position. As stated earlier, the current "A1" rating by Moody's is now equivalent to or a notch above the credit ratings of other two rating agencies. On page 2 of the same May 2021 report that the current rating was assigned, Moody's cited "Factors that could lead to a downgrade" which include (1) "a material deterioration in the credit supportiveness of the Michigan regulatory environment;" or (2) the cash flow to debt ratio "CFO pre-W/C to debt" falling below 18% on a sustained basis.[71]

The more recent Moody's report from May 2023 on page 1 shows the Company's performance under this ratio at 20.2% for 2022 and 22.6% for 2021 both of which are above the 18% threshold level noted above.[72] Among the concerns noted in the sections titled "Credit Challenges" and "Rating Outlook" noted on page 2 of this report are higher leverage at the parent company, CMS Energy, and what Moody's refers to as a "robust capital investment plan" which means a high level of capital expenditures. As I note in other parts of my testimony, both of these factors are within the control of the Company.

Q. WHAT DID S&P STATE IN ITS MOST RECENT CREDIT REPORT ABOUT CONSUMERS ENERGY'S CREDIT PROFILE?

[70] See Case U-20322, Exhibit A-22 (MRB-8) at line 23.
[71] Exhibit A-31 (MRB-12)
[72] Exhibit AG-53 includes DR AG-CE-128 and the Moody's report dated May 31, 2023.

A. According to S&P's August 17, 2023 report, the Company's senior secured debt is rated as "A" by S&P (the middle of the "A" category).[73] Furthermore, on page 4 of this 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 Corp.

Page 5 of this S&P report shows this key ratio at 18.7% for 2022. S&P also estimated this ratio in the range of 18.2% to 19.8% for 2023 and 2024. These coverage ratios are not indicative of any concerns about a possible debt rating downgrade and are well above the 15% threshold set by S&P.

Q. DID THE COMPANY CALCULATE THE IMPACT ON THE RATING AGENCIES' CASH FLOW TO DEBT COVERAGE RATIOS IF THE EQUITY RATIO WAS SET BELOW 51.5% AND THE ROE BELOW 10.25%?

A. No. Starting on line 8 of page 15 of his direct testimony, Mr. Bleckman states that reducing the ROE below 10.25% and the common equity ratio below 51.5% could cause the Company's FFO to Debt ratio to drop below the established rating agency thresholds. However, in his testimony or exhibits, Mr. Bleckman does not provide any evidence to support this claim. In discovery, the AG asked the Company to substantiate Mr. Bleckman's claim with supporting analysis, calculations, and any notifications from rating

[73] Exhibit AG-54 includes DR AG-CE-128 and the S&P report dated August 17, 2023.

agencies that a lower ROE or equity ratio below those postulated by Mr. Bleckman would lead of a rating agency debt downgrade.

In its response, the Company could not provide any calculations or evidence to support Mr. Bleckman's claim, and instead admitted that it had not been informed by any rating agency of a potential debt downgrade if the equity ratio was set below 51.5% and the ROE below 10.25%.[74]

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 9.85%

A. Yes. In Exhibit AG-52, I calculated the Company's key cash flow to debt ratio for 2022 adjusted for the ROE of 9.85% that I advocate for in this case, as discussed below. In the financial statements filed with Securities and Exchange Commission on Form 10K, the Company's common equity level as of December 31, 2022 was $10.1 billion and its long-term debt including current maturities was $10.2 billion. From a financial reporting standpoint, which is the information used by Moody's and the other rating agencies, the December 31, 2022 financial position essentially reflects a balanced capital structure. Therefore, I made no further adjustment to the capital structure for the purpose of calculating the cash flow to debt ratio.

[74] Exhibit AG-55 includes DR AG-CE-0132.

For my calculation of the 2022 pro-forma cash flow to debt ratio, I start with Moody's actual calculated results on line 1. As mentioned above, no adjustment was necessary related to capital structure on line 2. On line 3, I adjusted the cash flow upward to reflect my recommended 9.85% ROE versus the 9.5% ROE actually achieved by the Company in 2022. The overall pro-forma results are shown on line 4 with a cash flow to debt ratio of 20.5%. This ratio is well above the 18% downgrade threshold noted by Moody's in its most recent report.[75] I have not presented any ratio results for S&P since the ratio calculations are similar, and the S&P downgrade threshold is lower at 15%.

By starting with actual Moody's 2022 results, items such as leases and short-term debt are already reflected in the cash flow and debt elements which determine the ratio. The Company often points to these as being "add-ons" which are not considered in looking at the permanent capital of CECO on a ratemaking basis. This analysis shows that the 9.85% ROE and 50% common equity ratio leaves the Company's cash flow ratios above the ratio levels where it could face a downgrade of its debt.

Q. WITNESS BLECKMAN ON PAGES 26 TO 27 OF HIS TESTIMONY ATTEMPTS TO JUSTIFY HIS PROPOSED 51.5% COMMON EQUITY RATIO BY NOTING THAT THE 51.5% IS EQUIVALENT TO A 49.3% RATIO ON AN ADJUSTED BASIS AFTER CONSIDERING LEASES, SHORT TERM DEBT AND SECURITIZATION DEBT. HOW DO YOU RESPOND?

[75] Moody's indicates this to be "18% on a sustained basis".

A. With his claim that the 51.5% common equity ratio is equivalent to a 49.3% common equity ratio inclusive of leases, short-term debt and securitization debt, Mr. Bleckman is trying to confuse the issue. These additional elements he points to are not part of the permanent capital structure of the Company. The Commission was aware of the Company's leases, short-term debt and securitization debt when it directed the Company to achieve a balanced capital structure. All of these elements date back to before the Commission's directive in Case U-17990 and will continue into the future. Mr. Bleckman made the same argument in the Company's last two fully litigated electric cases (Case No. U-20963 and U-21389) and I find it equally unpersuasive in this case.

In Case No. U-20963, the Company put forth the same argument and it was rejected by the Commission. In the December 22, 2021 order in that case, the Commission stated the following:

> When including securitization debt, short-term borrowings and leases, Consumers argues that its adjusted equity ratio for the test year is 50.7%...The ALJ found that Consumers had not "established that the capital structure equity ratio it recommends is "optimal" under any of the definitions it has offered or minimizes the cost of capital to ratepayers." PFD, pp. 286-287. She noted that the company's opinion of an acceptable capital structure was fluid because Consumers' primary concern was to maintain a consistent level of income based upon the combination of equity percentage and the return on equity level. The ALJ further concluded that the company's methodology of adding a dollar of equity to its capital structure for every dollar of short-term debt and leases, "implicitly increases the cost of each of these items well above the stated costs otherwise recovered from ratepayers" without justification. The ALJ agreed with the Staff and the Attorney General that the proposed adjustments "are at odds with the established ratemaking method that develops a weighted cost of capital based on the sources of financing rate base" The Commission agrees … the ALJ properly found that the Commission has previously rejected the company's

> assertion of a more balanced capital structure when considering the equity ratio from a credit rating agency perspective.[76]

For the same reasons pointed out in Case No. U-20963, the Commission should again reject the Company's arguments in this case.

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

A. There are several issues in the financial transactions between Consumers Energy and its parent company, CMS Energy ("CMS"), which cannot be ignored when analyzing the Company's proposed capital structure. First, CMS can make the Company's common equity ratio whatever it wants. The same executive management that runs CMS Energy also operates the Company. Management can direct at any time how much in capital it wants to inject into the Company from the parent company and call it equity capital. In fact, it has done just that over the years. In response to a discovery request, the Company has stated that the injection of common equity from CMS Energy is at the discretion of management with no approval from the Board of Directors.[77] Such freedom to call for equity capital would not exist if Consumers Energy itself was a publicly traded company.

Over the five years 2018 to 2023, Consumers Energy's Common Equity has increased from $6.9 billion in 2018 to $10.8 billion in 2023—an increase of $3.9 billion. An analysis

[76] Case U-20963 Order page 201 and 203.
[77] CECo response to discovery request U-18322-AG-CE-439.

of the Company's financial statements filed with the Securities and Exchange Commission shows that the $3.9 billion increase is due to the following factors:

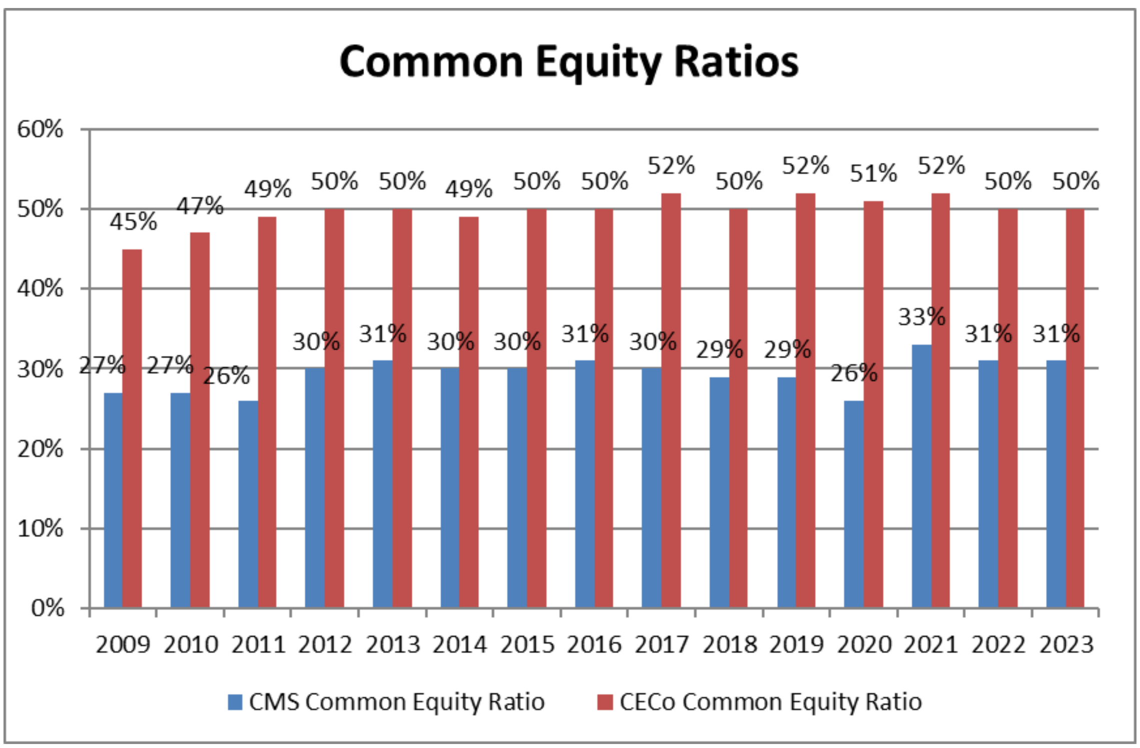
Table 1		
Consumers Energy		
Common Equity Change for Five Years Ended Dec. 2023		
		$ Billions
1	Net Income of Consumers Energy	**$ 4.2**
2	Dividends Paid to CMS	**(3.4)**
3	New CMS Investment in Consumers Energy	**3.1**
4	**Total Change in Common Equity**	**$ 3.9**

Table 2		
CMS Energy		
CMS Funds Available to Invest in CECo for Five Years Ended Dec. 2023		
		$ Billions
a.	Dividends From Consumers Energy	**$ 3.4**
b.	Less: Dividends to CMS Shareholders	**(2.5)**
c.	Plus: Other CMS Activity	**(0.2)**
d.	Sub Total	**0.7**
e.	Increase in Parent Company Debt	**1.9**
f.	CMS Net Equity Issued	**0.5**
g.	**Funds For New CMS Investment in Consumers Energy**	**$ 3.1**

Clearly, of the $3.1 billion of new equity invested by CMS, $1.9 billion (or 61%) is from new CMS debt.

Second, to further support my point, CMS Energy is a frequent issuer of long-term debt in the capital markets. Over the last five years, CMS parent-only debt has increased from $3.0 billion at year end 2018 to $4.9 billion at year end 2023.[78] Yet the only substantive business CMS Energy owns is Consumers Energy.

The following chart displays the gap in equity capital between Consumers Energy and CMS over the years 2009 to 2023. While cash raised from the issuance of long-term debt at CMS is not immediately injected into Consumers Energy, it is nonetheless being utilized in part to fund CMS's so-called equity infusions into CECo.



[78] From SEC filings on Form 10-K for the years ended 2019 (p. 126) and 2023 (p. 124).

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

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

The excessive debt and low common equity ratio at CMS (31% at year-end 2023) are a continuing concern for the rating agencies when assessing the debt rating of Consumers Energy. For example, in its May 31, 2023 credit update report on the Company, Moody's notes in the section "Rating Outlook" that their "… stable outlook also incorporates our view … that debt levels at the parent will not increase materially".[79] Similarly, page 2 of the Moody's report issued two years earlier on May 10, 2021 contains a substantially similar comment. Yet, CMS continues to 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

[79] Exhibit AG-53 includes the May 31, 2023 Moody's Report, (see page 2), provided in DR AG-CE-128.

more equity capital. The result has been higher interest costs for customers. Partially to compensate for this significant leverage at CMS, the Company now wants a higher equity ratio in the capital structure that will further increase costs to customers.

Q. **YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP USED TO ASSESS THE COST OF COMMON EQUITY APPROXIMATES 46%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE COMMON EQUITY RATIO FOR THE COMPANY.**

A. As shown in Exhibit AG-47, the average common equity ratio of the peer company group for 2023 was 45.7%. The cost of equity for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure. Thus, it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible, in order to have consistency with the cost of equity capital derived from those peer group companies. The Company's proposed common equity capital ratio of 51.5% creates a disconnect that is not acceptable and is also more costly to customers.

Q. WITNESS BLECKMAN SPONSORS EXHIBIT A-32 (MRB-10) SHOWING THE COMMON EQUITY RATIOS FOR VARIOUS GAS AND ELECTRIC UTILITY COMPANIES SUPPOSEDLY DECIDED IN RATE CASES DURING 2020 TO 2023. THE EXHIBIT SHOWS AN AVERAGE COMMON EQUITY RATIO OF 54.03%. DO YOU FIND THIS EXHIBIT WORTHY OF CONSIDERATION?

A. No. Mr. Bleckman's purpose in presenting this exhibit showing an average common equity ratio of 54.03% is an attempt to support his recommended 51.5% equity ratio and to suggest that his rate is conservative and very reasonable compared to the equity ratios approved for other utility companies.

There are several problems with the information provided by Mr. Bleckman. First, it should be pointed out that for purposes of setting an equity ratio many of the companies listed in Exhibit A-32 have their equity ratios set by their commissions solely by reference to long-term debt and common equity capital. However, the reality is that short-term debt is employed as a permanent financing tool by several companies in Mr. Bleckman's exhibit, which when considered in the calculation of the capital structure as permanent debt by the regulatory agencies results in a lower equity ratio. This is true of all of the companies in Texas and Oklahoma, as can be seen in the workpapers supporting Exhibit A-32. For example, workpaper #38 shows the Texas Gas Service (a One Gas subsidiary) capital structure as 40.26% long-term debt and 59.74% common equity. In reality, One Gas's utilized a relatively permanent layer of short-term debt in 2023 which averaged $228 million, or approximately 5% of total capital employed. Taking this additional debt into consideration lowers the percent of common equity in the capital structures well below the 59.74%.

Spire Missouri is another example. A review of workpaper #39 shows the capital structure from the rate case with 49.66% common equity, 41.83% long-term debt and 8.51% short-term debt. For purposes of Exhibit A-32 (MRB-10), Mr. Bleckman recomputes a 54.28%

equity ratio at the bottom of workpaper #39 by looking only to common equity and long-term debt. This recalculation is not necessary because the short-term debt is a permanent layer of the capital structure.

The Commission should recognize that while CECo uses short-term debt strictly as a seasonal financing tool, many other utilities use it both to meet short-term and long-term capital needs. Although a permanent layer of short-term debt can reduce financing costs, it exposes utilities to greater financial risk due to fluctuating interest rates requiring a thicker layer of common equity capital. This is not a situation faced by Consumers Energy.

Second, other companies on this exhibit are smaller operating units. For example, line 10 of the exhibit shows Cheyenne Light Fuel and Power with a 52% equity ratio. This small company sells gas and electricity to approximately 80,000 customers in Wyoming. Another small company unit is CenterPoint's Arkansas operation (line 11) with a capital base of only $658 million according to Mr. Bleckman's workpapers. Higher equity ratios for these smaller companies and operating units may be warranted due to the fact that small companies have less financial flexibility and debt borrowing limitations.

Despite Mr. Bleckman's objective to represent that the utilities and related equity ratios in Exhibit A-32 are comparable to Consumers Energy, the evidence shows otherwise. The Commission should disregard this flawed and misleading information.

Q. WHAT IS THE REVENUE REQUIREMENT SAVINGS RELATED TO A LOWER COMMON EQUITY RATIO OF 50.0% IN COMPARISON TO THE COMPANY'S PROPOSED EQUITY RATIO OF 51.5%?

A. The difference is approximately $13.5 million annually. This reflects (a) the difference between the pre-tax cost of common equity of approximately 14.1% versus the cost of long-term debt of 4.3%; (b) the Company's proposed rate base of approximately $11.0 billion; and (c) the percentage of total capital being shifted from common equity to long term debt.

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

A. No. Except for the changes to common equity and long-term debt balances discussed above, I used the same balances in the capital structure sponsored by witness Bleckman in Exhibit A-14 (MRB-1), Schedule D1, page 1.

B. <u>COST OF CAPITAL</u>

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

A. I am recommending an overall return on capital of 5.96%, which includes a return on common equity of 9.85%, as shown in Exhibit AG-44. Even though the average ROE calculated under the three methods discussed below is slightly less than 9.85%, I have used a 9.85% 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 4.31% based upon Mr. Bleckman's recommendation.

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

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

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

A. For Short Term Debt and Deferred Taxes, I used the cost rates recommended by witness Bleckman. Cost rates for JDITC reflect those rates I used for the permanent capital sources.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-44.

A. To develop the overall cost of capital on line 12, column (f), I first developed the percentage weighting of each capital component in column (d) by dividing the individual capital balances in column (b) by the total of all capital components in that column. Next, I multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the values in column (f). The total of the individual values in column (f) is the total cost of capital of 5.96%.

Regarding the pretax weighted cost of capital on line 12, column (h), I multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income and other taxes paid by CECo for calculation of the pretax weighted cost of 7.35% 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-45.

A. Determining the cost of common equity for an enterprise or an industry group is inexact since investors can only estimate what the future cash flows from any enterprise may be over time. Because of this uncertainty, most financial experts will not rely solely on any one particular method. To determine the cost of common equity, I utilize three approaches. These are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and the Utility Risk Premium approach.

While Exhibit AG-45 shows an average ROE of 9.84% from the three methodologies, I round this rate up and recommend an allowed rate of return on equity of 9.85% 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 9 utility companies followed by the Value Line Investment Survey in its "Natural Gas Utility Industry" section. I have eliminated two of these companies from consideration which are (a) Southwest Gas Holdings which is reorganizing by selling its pipeline business and seeking to spin-off its pipeline construction business; and (b) UGI Corporation due to its foreign investments and heavy reliance on propane sales.

Additionally, I have added one other company to my peer group which Value Line classifies as an electric utility. The additional company is Black Hills. This company earns approximately 50% of its income from natural gas distribution and as such is suitable to be included in a natural gas distribution peer group.

The result is the group of 8 companies shown in Exhibit AG-46, all of which have growing earnings and dividends.

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

A. The Company's peer group contains all the individual companies in my peer group except for Chesapeake Utilities and includes three other companies which I discuss below.

The additional companies included by witness Wehner in his peer group are Center Point Energy, DTE Energy, and WEC Energy. Center Point has indicated its intent to sell its gas businesses in Mississippi and Louisiana for $1.2 billion and as such, the company's stock price has been affected by the potential divesture of assets. The other two companies are primarily dependent upon electric assets and earnings and derive approximately 20% of their income from the natural gas business. These two companies are not a good fit for inclusion in a group of peer companies for determining the of cost of common equity for a company in the natural gas business.

Discounted Cash Flow (DCF) Cost of Equity Method

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

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

$$R = D/P + g$$

where "R" = the Required Equity Return

"D/P" = the Dividend Yield on the Security

and "g" = the expected growth rate in dividends

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-46. The stock price information in column (c) of this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from February 15 to March 31, 2024. The annual dividend in column (d) is the forecasted average dividend level for 2024 and 2025 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 the five years from 2023 to 2028 per Value Line; and (2) the earnings growth estimate by stock analysts over the next five years which is available from Yahoo.com.

The resulting calculation of the DCF Method is an average return on common equity for the proxy group of 9.51%.

Q. PLEASE ASSESS THE RESULTS OF THE DCF ANALYSIS YOU PERFORMED.

A. The DCF analysis relies upon financial market information for the dividend yield portion of the equation. However, it also relies upon judgments of dividend and earnings growth prospects of security analysts which may or may not be consistent with the beliefs of investors. I place a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other methods in determining the cost of common equity.

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

A. The 9.51% rate I calculated is lower than the Company's "analyst-based" DCF calculation of 10.22% which is shown on page 5 of Exhibit A-14 (TAW-1). The growth rates in this exhibit page average to 5.80% in column (i) based on witness Wehner's use of "Consensus Analyst DPS Growth" rates (excluding Center Point Energy). My growth rates average 5.35%. The DPS Growth or dividends per share growth is an inferior approach since dividends, in the short-term, may be growing at a rate that is different than earnings per share. In this regard, most cost of capital practitioners use earnings growth estimates since it is earnings over the long-term that enable dividend growth. Mr. Wehner's 5.8% growth rate is slightly higher compared to my calculation and accounts for most of the difference in the two DCF equity rates.

Capital Asset Pricing Model

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 my Peer Group is 0.88.

Q. PLEASE EXPLAIN EXHIBIT AG-47 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-47 shows the results of the CAPM method based upon (1) a 4.10% risk-free rate; (2) the Betas of the companies in the Peer Group taken from Value Line; and (3) the 7.17% historical Market Risk Premium (R_p) return from the years 1926 to 2020 developed by Company witness Wehner in Exhibit A-14 (TAW-1), Schedule D-5, page 7, line 51.

Regarding the use of a risk-free rate for CAPM purposes, I used a 4.10% rate which is the average 30-year U.S. Treasury Bond for 2024 and 2025 determined from economic projections provided by the Company[80].

The result of my CAPM approach using the 6.32% adjusted risk premium (7.17% Risk Premium x 0.88 Beta) plus the 4.10% risk-free rate is a cost of equity capital of 10.42% 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. As such, the only risk to the investor is from 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.

[80] Exhibit AG-3 includes DR AG-CE-199 Attachments 1 for the source of the 4.10% rate from the Blue Chip Financial Forecast.

Utility Risk Premium Approach

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

A. In general, the cost of common equity for a peer group of utility companies can be estimated by (1) projecting the cost of debt for the peer group and adding to this cost (2) the average return differential of utility common stocks over utility bonds.

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-48 shows the components required to derive a cost of common equity capital for the peer companies on lines 3 and 4. The 5.78% on line 3 is projected average rate for utility bonds rated "A" and "BBB". This rate is determined in footnote 2 of the exhibit from the forecasted 30-year utility bond rate. The spread rate of 4.15% on line 4 of the exhibit is the historical rate of gas utility returns versus "A" rated debt yields from 1952 to the present as developed by witness Wehner.[81] The total of the two rates equals the Risk Premium return rate of 9.93% on line 5 of the exhibit.

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

[81] See Company Exhibit A-14 (TAW-1), Schedule D-5, page 8, line 72.

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

	CAPM	ECAPM	Utility Risk Prem.
Attorney General ROE	10.42%	N/A	9.93%
Company ROE	13.61%	13.76%	10.62%

Substantially all of the difference between my 9.93% Utility Risk Premium rate and the Company's 10.62% rate is due to assumptions used related to the risk-free rate (30-year U.S. Treasury bond rate) which is a factor in the CAPM as well as the Utility Risk Premium approach. The Company used a 4.73% rate whereas I used a 4.10% rate (a 62-basis point difference). The issue of the proper rate to use in these analyses is discussed below.

Q. PLEASE EXPLAIN THE COMPANY'S DECISION TO USE A 4.73% 30 YEAR U.S. TREASURY RATE AS THE RISK FREE RATE AND WHAT IS YOUR VIEW REGARDING THE USE OF THIS RATE TO DEVELOP ROE ESTIMATES FOR THE PROJECTED TEST YEAR.

A. The use of this 4.73% rate is inappropriate since it is stale at this point. It is clear from some of the schedules in Mr. Wehner's exhibit pages that the forecasted 4.73% rate was developed sometime in the fourth quarter of 2023 prior to filing this rate case.[82] During

[82] Exhibit A-14 (TAW-1) page 10 shows a date of October 5, 2023

October 2023, the 30-year U.S. Treasury bond rate ranged from 4.73% to 5.09%. In this environment, a 4.73% projected rate for use in the projected test year probably seemed reasonable. However, since October 2023, 30-year U.S. Treasury bond rates have declined and at year-end 2023 stood at 4.03%. More recent projections, as of March 2024, show that 30-year U.S. Treasury bond rates will decline to approximately 4.10% in the 2024/2025 period. Therefore, I have used this more recent information to develop my cost of capital in this case.

Q. WHAT IS MR. WEHNER'S RATIONALE FOR THE USE OF A PROJECTED RISK PREMIUM FOR DEVELOPMENT OF HIS CAPM AND ECAPM ROE ESTIMATES?

Mr. Wehner presents the result of his CAPM cost of capital methodology on page 2 of Exhibit A-14 (TAW-1), which shows a 13.61% ROE result using a projected 9.81% risk premium. The projected risk premium is approximately 275 basis points above the historical 1926 to 2022 long-term average of 7.17%. For his ECAPM cost of capital methodology, Mr. Wehner also uses the same 9.81% risk premium. Mr. Wehner discusses his rationale for the use of a projected risk premium and the ECAPM method beginning on page 25 of his direct testimony where he states "…Market beta calculates a low result for a company with a low correlation to the broad market when, in fact, the Company could experience high stock market volatility that simply is not correlated with the market…"

and "…utilities are interest rate sensitive and exposed to regulatory risk, neither of which…is captured by the traditional CAPM estimate".

Mr. Wehner further states on page 26 of his testimony that "In order to adjust for the shortcomings of the CAPM model, the Company applied projections for the risk-free rate and the risk premium for the test year in this case…" and …" also performed an ECAPM analysis to further address the shortcomings."

Q. WHAT IS YOUR VIEW OF WITNESS WEHNER'S RATIONALE FOR USING A PROJECTED RISK PREMIUM BECAUSE OF SOME PERCEIVED SHORTCOMING WITH UTILITY STOCK BETAS.

A. Mr. Wehner's rationale for using a projected risk premium because utilities' market betas do not reflect regulatory risk and interest rate sensitivity has no basis in fact, goes counter to established financial methodologies, and is simply his own creation to inflate the ROE outcome. The Value Line Betas are widely used by cost of capital experts and have long been established as the gold standard when calculating the cost of capital using the CAPM methodology. Additionally, the utility betas reflect the volatility of the utility stocks against the stock market and in that regard reflect any volatility caused by interest rates. They also reflect the impact of regulation, which typically protects utilities from competition and market volatility, and other factors that affect utility stocks.

Therefore, Mr. Wehner's logic is seriously flawed and the Commission should give no weight to his arguments. Next in my testimony, I will discuss why the Commission should also disregard Mr. Wehner's use of the projected risk premiums.

Q. PLEASE EXPLAIN DISCUSS MR. WEHNER'S USE OF A PROJECTED RISK PREMIUM APPLIED TO TWO OF HIS COST OF CAPITAL METHODOLOGIES.

A. Mr. Wehner utilized a projected risk premium for his Projected CAPM and Projected ECAPM calculations that is based upon projected returns in the stock market over the next five years compiled from Bloomberg data during October 2023. Mr. Wehner developed the projected risk premium of 9.81% for his CAPM and ECAPM on page 10 of Exhibit A-14. As I stated earlier, this projected risk premium is approximately 275 basis points higher than the historical average risk premium for the years 1926 to 2022.

Q. WHAT SHORTCOMING DO YOU SEE WITH THE PROJECTED RISK PREMIUM RATE DEVELOPED BY MR. WEHNER?

A. Mr. Wehner arrived at the 9.81% rate by using Bloomberg financial data as of October 2023. Bloomberg's forecasted stock market returns for the upcoming five years reflect a result determined at a point in time in early October 2023. This point in time calculation is faulty and not useful because it does not reflect investors' return expectation over the long term. To prove the point, the S&P 500 has advanced by approximately 22% since October 2023, and a similar analysis today would yield a lower result given the stock market's rapid advance in the past six months. Therefore, the projected risk premium calculated by Mr. Wehner is unreliable and should be disregarded by the Commission.

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 and utility bond yields 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 result in very high ROEs during periods of economic expansion, as Mr. Wehner has done under his unconventional approach, and much lower premiums during periods of economic declines. For the Commission to adopt this approach, it would be akin to only selecting the positive return years in the Ibbotson series over the 93-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.

These concerns are also echoed by Dr. Roger Morin, a recognized expert on regulatory finance matters, who strongly supports 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.

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

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

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

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

A. No. On pages 53 and 54 of his testimony, Mr. Wehner points to a case in Alaska decided in 2002 where the Alaska Commission gave formal recognition to an adjustment for ECAPM, but he presents no more recent information on the Alaska Commission's views on this methodology. As I have discussed in the Company's prior rate cases, there is no widespread acceptance of the ECAPM among state regulatory commissions in the United States and inferences made by the Company to the contrary do not stand-up to in-depth review.

For example, 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. In a pre-2016 order in Case 9326, the Maryland Commission stated that they found the DCF and ECAPM "helpful". However, in a subsequent case in November 2016 involving PEPCO (case 9418) the result is different. As shown in the summary positions articulated in the order in this case, no party involved in the proceedings, other than the company, put forth an ECAPM ROE estimate. In that 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 its decision, the Maryland commission expressed no position on ECAPM. I am not aware of any more recent cases that show a change in the commission's view of the ECAPM methodology.

Mr. Wehner's claim that the New York State Public Service Commission uses a so-called "zero beta" CAPM model that supposedly is similar to the ECAPM is unsubstantiated. Also, the fact that other cost of capital practitioners representing utility companies have used the ECAPM model in other rate cases to boost the proposed ROE rate does not mean that the methodology has been endorsed by the regulatory commissions adjudicating those rate cases.

In summary, the use of ECAPM is controversial and not widely accepted by state regulatory commissions 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 10.22% 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 10.25% relies on this estimated return on equity rate.

However, 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 five 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. If utility commissions were to rely upon this methodology, utilities would effectively be setting their own allowed ROE or highly influencing those ROEs by estimating ever increasing EPS.

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

Q. ON EXHIBIT AG-49 YOU PROVIDE INFORMATION REGARDING THE MIX OF UTILITY AND NON-UTILITY BUSINESSES OF THE PEER GROUP YOU

USE. WHAT DOES THIS ANALYSIS REVEAL ABOUT THE RISKS OF THE PEER GROUP RELATIVE TO THE COMPANY'S GAS BUSINESS?

A. In general, the peer group has a higher degree of risk compared to the gas business of Consumers Energy. Some companies in the peer group are involved in energy ventures, energy services, and gas marketing. The non-utility, and often non-regulated, businesses place the peer group at greater risk. Also, the peer group companies are more financially leveraged with higher debt as a percentage of total capital, which makes them riskier. Therefore, the cost of equity I calculated and recommend in this rate based on that peer group is somewhat higher than what would be applicable to Consumers Energy and thus more favorable to the Company.

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

A. Exhibit AG-51 shows the ROEs approved by state regulatory commissions in 2022 and 2023 for U.S. gas utilities. The majority of the 37 ROE decisions in 2022 and 34 decisions in 2023 are at rates well below 9.9%, which is CECo's current authorized ROE. As shown on page three of this exhibit, only two decisions in 2022 and three decisions in 2023 are at rates of 9.9% or greater. These higher rates are primarily from regulatory commissions in California, Florida and Michigan. ROEs in California have been at or above 10% reflecting the unique challenges for utilities in that state with wildfires and earthquakes. The higher ROEs in Florida pertain to two very small utilities and also reflect damage to property from hurricanes which is an on-going risk.

For most of the other gas utilities that have business and financial risks comparable to Consumers Energy's operations, the ROE rates have averaged around 9.5% in the past two years. This evidence supports my proposed ROE rate of 9.85% as quite reasonable and suggests the Company's current ROE rate of 9.90% is excessive and "out of line" with comparable gas utilities. The Company's proposed ROE rate of 10.25% is even further removed from reality and clearly unsupportable.

Q. IN THIS RATE CASE, MR. BLECKMAN SPONSORS EXHIBIT A-33 (MRB-11) SHOWING THE ROE AND COMMON EQUITY RATIOS OF SELECT UTILITY COMPANIES. WHAT IS YOUR ASSESSMENT?

A. Much of the information in Exhibit A-33 is incorrect, misleading, and does not provide a proper context for the metrics noted in the exhibit. There are several problems with the information presented by Mr. Bleckman.

First, with regard to Florida Power & Light, the 10.60% ROE was established by the Florida Commission in 2021 as part of a multi-year agreement covering the years 2022 to 2025. Under this new agreement rate increases are capped, and any other relief would be dependent upon extraordinary circumstances.[83] In addition, this Company's service territory is buffeted by hurricanes each year which can disrupt electric service for prolonged periods and potentially reduce revenues and profits. The ROE rate granted to Florida utilities is not applicable to Consumers Energy's gas business.

[83] NextEra 2022 Form 10-K, page 9.

Second, Alabama Power, a Southern Company subsidiary, has a 55% Common Equity ratio and a 10.9% ROE. The utility may potentially increase it rates each year but no more than 8% on a rolling two-year basis. However, the increases are limited to 4% on average annually. The increases are authorized under the company's Rate RSE (established before 2016) which is determined by considering the level of earned returns on equity and the percentage of equity in the capital structure based on the company's Weighted Equity Cost Rate (WECR).[84]

In 2018, the Alabama Commission and the company agreed to a higher common equity ratio of 55% by 2025 from 47% in December 2018. The change to Rate RSE for Alabama Power was approved in May 2018 with no compensating rate increases and the company at that time consented to a nominal reduction in the WECR with no annual Rate RSE increases in 2019, 2020 and 2022. Rates were increased by 4.09% in 2021, but the Company also made refunds to customer via bill credits in the amount of $50 million for 2020, $181 million for 2021, and $62 million for 2022.[85] What is happening in this situation is that the Company is increasing the common equity ratio gradually with no compensating increases in the WECR. The practical effect of these rate actions is to reflect recognition of a lower cost of common equity. This special rate and capital structure arrangement is not applicable to Consumers Energy for purposes of establishing an appropriate ROE rate in this rate case.

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[84] Southern Company Form 2022 10-K starting at Page II-139 under "Rate RSE".
[85] Id.

Third, the exhibit shows Georgia Power, another Southern Company subsidiary, with a 56% common equity ratio and an 10.50% authorized ROE. Georgia Power is in a special situation involving significant expenditures for two nuclear power plants where (1) the original contractor declared bankruptcy; and (2) the Company has been forced to write-off approximately $2.0 billion of cost overruns in 2021 and 2022; and (3) the Company has still not completed one of the two new nuclear units and faces uncertainty regarding the future recoverability of costs related to the new nuclear generating units.[86] The Georgia Commission has been very supportive of the company through this troubled time in its history. The ROE and capital structure for Georgia Power are not applicable to Consumers Energy given the unusual circumstances.

Fourth, with regard to WEC, which owns gas and electric utilities in Wisconsin and other jurisdictions, the 10.14% ROE shown in the exhibit is unsupported and faulty. Recent decisions from the Wisconsin Commission in general rate cases have granted ROEs of 9.80%.[87] It appears that Mr. Bleckman may have boosted the ROE rate in his chart by including Limited Issue Riders. These riders are not applicable to a general rate case and not applicable to Consumers Energy in this proceeding.

Fifth, the information regarding IPL is inaccurate and misleading. Some of the electric assets of IPL have 10% or higher ROEs, but these pertain to certain electric generating and

[86] Id. page II-147.
[87] Regulatory Research Associates 2022 Report.

transmission assets. The authorized ROE and equity ratio for IPL's gas distribution business is 9.80% and 53.9%, respectively.[88]

Sixth, for UGI, all of this utility's recent general rate cases in 2020 through 2022 have been settled without published rate metrics. So, the information shown in this exhibit is stale or inapplicable.

In summary, Mr. Bleckman's attempt to inflate the Company's ROE recommendation by pointing to select and inapplicable ROE rates granted to other utilities fails to provide convincing evidence and should be rejected by the Commission.

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

A. No. In recent general rate case proceedings, certain rate case applicants have raised arguments that they should receive higher ROEs to ensure the financial soundness of the business and to maintain their strong ability to attract capital in addition to being compensated for risk. Exhibit AG-51 shows several gas utilities that have accessed the capital markets at competitive interest rates since receiving a ROE near or below the average rate of 9.50%.

[88] See Alliant Energy's 2021 Form 10-K, page 32.

Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs near or below the industry average. 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-50 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 9.23%. Yet, this group of companies has an average Market to Book common equity value ratio of approximately 1.5 times.

This information is provided to dispel the myth that the Company must receive a high ROE above the industry average, or it will face dire consequences in the financial markets. The fact that the Company needs to raise capital because of a large capital investment program to upgrade its infrastructure and for other purposes is not unique to Consumers Energy. Most gas utilities face the same issues and are able to raise capital with ROEs at or near the 9.5% average rate. Therefore, this issue is another “red herring”.

Q. HAS THE MARKET FOR NEW LONG-TERM DEBT BEEN RECEPTIVE TO NEW UTILITY DEBT ISSUES IN 2022 AND 2023?

A. Yes. As shown on Exhibit A-31(MRB-9), the market for new utility debt issues has been very robust with over 350 new issues completed in 2022 and the first nine months of 2023. Also, as can be seen from Exhibit AG-51, a large number of utility companies issued new debt shortly after receiving a rate order with ROEs below 9.5%.

Consumers Energy issued $500 million of long-term debt in July 2023 at an interest rate of 4.9% and a 6-year term. Also, in January and February of 2023, Consumers Energy issued $700 million of new 10-year debt at an interest rate of 4.625% and $425 million of new 5-year debt at 4.65%. Accordingly, the debt markets are receptive to utility companies' capital raising activities.

Q. IN CERTAIN PRIOR RATE CASES THE COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO AUTHORIZE A HIGHER 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 supporting point, in Exhibit AG-56, 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 volatility as the general stock market. This is reflected in the average Beta value of 0.88 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 a utility's ROE should reflect investors' concerns with stock market volatility.

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

A. In Exhibit AG-45, I have summarized the cost of equity rates from the three methods I discussed above. The range of returns for the industry peer group is from 9.51% at the low end, using the DCF approach and 10.29% at the high end using the CAPM 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 and less weight to the other methods. In this regard, on line 4 of Exhibit AG-45, I have calculated a weighted return on equity from 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 9.84%. To this result I have added one basis point to round up the calculated result to 9.85%.

Q. SHOULD THE COMMISSION MAKE FURTHER ADJUSTMENTS TO THE 9.85% ROE RATE YOU HAVE PROPOSED FOR ANTICIPATED INCREASES IN INTEREST RATES DURING THE PROJECTED TEST YEAR?

A. No. The 4.10% forecasted interest rate for the 30-year U.S. Treasury rate that I used in my calculation of the ROE rate in this rate case takes into consideration that the Federal Reserve will likely decrease interest rates later in 2024 and into 2025. Although forecasted interest rates may change from day to day, there are no current expectations by economists that the Federal Reserve will raise interest rates during the projected test year ending September 2025. Therefore, I recommend that the Commission accept my prosed ROE rate of 9.85% without further adjustments for potential increases in interest rates.

Q. IF THE COMMISSION APPROVES A 9.90% COST OF COMMON EQUITY IN THIS CASE, WHAT IS THE ADDITIONAL COST TO CUSTOMERS COMPARED TO AN ROE OF 9.85%.

A. If the Commission were to maintain the current 9.90% ROE in this case versus a 9.85% ROE, the additional cost to customers is approximately $3.2 million annually. There is absolutely no need to burden customers with this additional cost, when historically the Company often has been earning well above its true cost of common equity.

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

IX. Revenue

A. Gas Sales and Transportation Revenue

Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S PROJECTED LEVEL OF GAS SALES AND TRANSPORTATION VOLUMES?

A. In Exhibit A-15 (EJK-6), Schedules E-2, Company witness Erik Keaton presents the Company's forecast of gas sales and transportation deliveries for the projected test year ending September 2025. The Company forecasted total gas sales of 221.9 billion cubic feet (Bcf) and end-user transportation deliveries of 89.3 Bcf for total gas deliveries of 311.2 Bcf for the projected test year. The projected sales represent a decrease of approximately 4.0 Bcf from the actual weather-normalized sales in 2022, while the projected transportation gas volumes represent an increase of 6.5 Bcf from weather-normalized 2022 volumes.[89]

According to Mr. Keaton's direct testimony and responses to discovery, the Company calculated the forecasted sales based on various regression projection models applied to customers' historical gas consumption during the January 2013 to March 2023 timeframe. The models also develop or make use of other historical and projected data, including number of customers, weather degree days, population changes, manufacturing activity, and other econometric data. External to the regression model, the Company made certain

[89] Exhibit A-16 (EKJ-14), Schedule E-10, lines 12 and 13, columns (a) and (d).

volume adjustments for expected energy waste reductions and other subjective adjustments discussed later in my testimony.

After reviewing the Company's sales and transportation forecast by customer class against the historical weather-normalized gas deliveries, I determined that the Company has captured the recent historical trend in gas deliveries to industrial sales customers and large transportation service users relatively well, and I do not dispute those forecasts. However, I believe that the Company has underestimated residential and commercial sales as well as commercial transportation volumes and the related revenues for the projected test year by a significant amount.

Q. WHAT IS THE BASIS FOR YOUR CONCLUSION THAT RESIDENTIAL AND COMMERCIAL GAS SALES ARE UNDERSTATED?

A. In response to discovery, the Company provided actual weather-normalized gas sales and the number of customers for each year from 2018 to 2023 and for the forecasted years 2024, 2025, and the projected test year. From the data provided by the Company, in Exhibit AG-57, I calculated the average weather-normalized annual gas usage per customer for each of the customer classes. The analysis on lines 1 and 2 of Exhibit AG-57 shows that from 2018 to 2023, the average annual gas usage per residential customer declined from 95.92 Mcf to 93.97 Mcf, or an average of 0.4% annually. In contrast, the Company has projected a decline in gas usage of 1.0% in 2024 with an additional decline of 0.6% in 2025 for a cumulative decline of 1.5% between 2023 and the projected test year. The Company's sales forecast results in average annual gas usage per residential customer of 92.57 Mcf, which is the lowest level since at least 2018.

For commercial customers, the analysis on lines 4 and 5 of Exhibit AG-57 shows that the average usage per customer decreased between 2018 and 2023 from 447.71 Mcf to 438.58 Mcf. Over this period, the average annual decrease in usage per customer was also 0.4%. However, the Company's sales forecast shows the average usage per customer declining 2.6% in 2024 from 2023 with a further decrease in 2025 for a cumulative decline of 3.1% from 2023 to the end of the projected test year. This decline comes despite the Company forecasting an increase of approximately 650 commercial sales customers from 2023 to the projected test year, as shown on line 24 of Exhibit AG-57. Although the Energy Waste Reduction (EWR) program pursued by the Company will have some impact on customer usage, the forecasted increase in the number of customers should be a mitigating factor against the loss of sales from the 1% targeted reduction in energy conservation.

Regarding the commercial transportation volumes, the average usage per customer has generally climbed since 2018 from 9,425.30 Mcf to 9,754.86 Mcf in 2023 with an average growth rate of 0.7%. However, for 2024, the Company forecasted a decline in the average usage of 8.1% with a further decrease of 0.4% in 2025. The two consecutive forecasted declines in usage translate to a total decline of 8.4% between 2023 and the projected test year. Similar to the commercial sales, the number of customers taking service under the commercial transportation class increased by 69 customers from 2023 to the projected test year.[90]

The significant decline in gas usage in residential and commercial sales, as well commercial transportation, between 2023 and the projected test year is highly unusual and unsupported.

Q. DID THE COMPANY'S FILED TESTIMONY EXPLAIN THE CHANGES IN CUSTOMER USAGE THAT YOU HAVE HIGHLIGHTED ABOVE?

A. No. In his direct testimony, Mr. Keaton describes the forecasting process for gas sales and end user transportation volumes, but does not analyze, explain, or support changes in gas volumes usage between historical and forecasted periods by customer class. In discovery, the Attorney General asked the Company to provide any adjustments to the forecasted gas deliveries made outside of the linear regression models used to develop the base forecast. In response, the Company provided two external adjustments.[91]

The first pertains to the EWR lost sales, which the Company forecasted at approximately 1% of recent historical sales. This rate of decline appears to be overly optimistic given that over the five-year period from 2018 to 2028, the average annual gas usage for residential customers has decline by only 0.4%, or less than half the EWR assumed rate of reduction. Although customer growth may have offset some of the EWR losses, the 1%

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[90] Exhibit AG-57, line 27.
[91] Exhibit AG-58 includes DR AG-CE-0335 with Attachment 1 and WP-EJK-8.

EWR loss rate does not appear realistic, and it is likely understating future customer gas usage in the Company's forecast.

Second, the Company identified volume additions for the projected test year of 4 Bcf for commercial sales and 1.2 Bcf for commercial transportation, which were calculated outside of the forecasting model. Although the Company did not explain the reasons for these external adjustments, they are likely due to shortcomings within the forecasting model that understated forecasted sales for the projected test year. In Case No. U-21308, the Company made similar external adjustments to the model and explained them by stating that "…the regression model results felt too low."[92] In other words, the regression model did not forecast reasonable sales and transportation volumes for those customer classes. From my analysis in Exhibit AG-57, it seems that the regression model also under-forecasted sales for residential customers.

Supporting that point also is the fact that sales and transportation volume data used in the regression model spans from January 2013 to March 2023. During that period, the Company experienced a significant decline in gas sales and transportation volumes in 2020, which lingered into 2021, due to the Covid-19 pandemic. The significant decline in gas deliveries and usage is shown in Exhibit AG-57, and particularly in the commercial and industrial classes for 2020 and for residential customers in 2021.

[92] U-21308 DR ST-CE-0049, AG-CE-279 and AG-CE-490.

In discovery, the Attorney General asked the Company to explain whether any adjustments were made to the forecasting model or the forecasted volumes for the projected test year to take into consideration this significant reduction in customer usage during 2020 and 2021. In response, the Company stated that no adjustment had been made.[93] The failure to take this recent decline in customer usage into consideration likely had a depressing effect on the Company's forecasted sales for 2024, 2025, and the projected test year.

Given those shortcomings, the Commission should not rely on the Company's forecasted volumes for residential and commercial sales and for the commercial transportation gas deliveries.

Q. DID YOU CALCULATE REVISED RESIDENTIAL AND COMMERCIAL SALES AND TRANSPORTATION VOLUMES, AND THE RELATED DISTRIBUTION REVENUE ADJUSTMENTS BASED ON YOUR ANALYSIS?

A. Yes. Pages 1 through 3 of Exhibits AG-59 show the calculations of the incremental volumes and revenue for the forecasted test year for residential and commercial sales customers and for the commercial transportation customer class. To arrive at the revised volumes, I started with the actual weather-normalized sales per customer for 2023 from Exhibit AG-57 and adjusted those volumes either up or down based on the underlying average annual rate of growth, or decline, in sales from the five-year period 2018 to 2023. The calculation includes those adjustments for the 9 months ending September 2024 and

[93] Exhibit AG-58 includes DR AG-CE-335c showing the response.

for the 12 months ending September 2025. The adjusted gas usage per customer for the projected test year was then multiplied by the number of customers forecasted by the Company for the test projected year.

Based on those calculations, I forecasted residential sales of 159,359 MMcf for the projected test year, which is an increase of 1,275 MMcf over the Company's forecast. Based on the current distribution rate billed to residential customers, the additional sales result in incremental revenue of $6,656,000 for the projected test year. Similarly, for commercial sales customers, I forecasted higher sales of 2,566 MMcf for the projected test year for additional distribution sales revenue of $9,924,000. For this customer class, I allocated the incremental sales by rate schedule based on the allocation methodology provided by the Company and then applied the respective current distribution rates to calculate the incremental revenue.

For commercial transportation customers, I forecasted higher volumes of 2,608 MMcf for the projected test year for additional distribution transportation revenue of $4,402,000. For this customer class, I also allocated the incremental volumes by rate schedule based on the allocation methodology provided by the Company and then applied the respective current distribution rates to calculate the incremental revenue.

In total, the incremental forecasted revenue for the projected test year is $20,982,000.

Q. WHY DID YOU USE THE 2023 AVERAGE USAGE PER CUSTOMER AND THE HISTORICAL FIVE-YEAR RATE OF SALES GROWTH OR DECLINE TO FORECAST SALES FOR THE AFFECT CUSTOMER CLASSES?

A. The weather-normalized usage per customer for the year 2023 represent the most recent gas usage profile for those customer classes. As such, they are not tainted by the usage distortions that occurred in 2020 and 2021 from Covid-19. The five-year rate of growth, or decline, in sales and transportation volumes takes into consideration the historical actual effect of EWR losses and any offsetting changes in customer usage due to other factors. It represents a realistic trendline over multiple years to forecast sales and transportation volume changes that will begin in 9 months from 2023 with the start of the projected test year in October 2024. In that regard, it provides a more current and accurate forecast than the Company's forecasting model, which uses stale customer usage data from 10 years ago, starting in 2013, and which has been tainted by unusual events, such as the Covid pandemic.

Q. ON PAGE 8 OF HIS DIRECT TESTIMONY, MR. KEATON IMPLIES THAT HIS FORECASTING MODEL IS HIGHLY ACCURATE. HOW DO YOU RESPOND?

A. In his testimony, Mr. Keaton states that the mean absolute percentage error (MAPE), also known as the mean absolute percentage deviation, of his forecasting model is 1%. While that percentage may seem low, it means that on average the sales forecasted by the model are 4.0 Bcf lower or higher than the actual results. That 1% and 4.0 Bcf deviations were calculated on average over a 10-year period. In response to discovery, the Company provided the standard deviation by year and the volume variance. That information shows that in any year the standard deviations can range from nearly zero to 3.5% and the volume variance can range from near zero to 10 Bcf.[94]

As shown in Exhibit AG-59, the sales and transportation volume adjustments I have proposed total to 6.4 Bcf, which result in a revenue adjustment of nearly $21 million. Therefore, the 4.0 Bcf standard deviation volume variance that Mr. Keaton considers highly accurate can still result in tens of millions of dollars of lower or higher forecasted revenue.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The sales and transportation volumes and the related revenue forecasted by the Company for certain customer classes is understated and needs to be adjusted. I recommend that the Commission adopt my volume adjustments to residential and commercial sales, as well as commercial transportation deliveries, and similarly increase the revenue forecasted by the Company for the projected test year by $20,982,000.

IX. Operations and Maintenance Expenses

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

[94] Id. includes DR AG-CE-0336.

A. Exhibit A-13 (HLR-41), Schedule C-5, shows the Company forecasted total O&M expenses of $277.8 million for the projected test year.[95] While this expense level is $63.6 million lower than the historical test year, the 2022 historical expense includes $53.3 million of expenses for the Appliance Service Plan, which the Company has sold. This expense has been excluded from the project test year. After adjusting for this historical expense amount of $53.3 million, the reduction in expenses from the historical test year to the projected test year is $10.2 million.

The reduction reflects (a) lower pension expense from increased stock market returns, and (b) cost reductions in certain operations likely resulting from a recent corporate reorganization combined with an 8.5% reduction in headcount, (b) lower gas prices; and (c) the impact of technology on certain operations. In my testimony below, I recommend that the Company's forecasted O&M expense should be reduced further by $35.3 million. Exhibit AG-60 shows a summary of my proposed O&M expense adjustments.

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

A. Yes. I have analyzed O&M expenses by major department or area, and I have identified more appropriate and reasonable expense levels that the Commission should consider.

A. Inflationary Adjustments to O&M Expenses

[95] See line 31 of Exhibit A-13 (HLR-41), Schedule C-5, excluding LAUF and Company Use Gas.

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

A. No. Given the similarity in the forecasted rate of inflation I developed from more recent CPI forecasted rates, I do not see a need to adjust the Company's forecasted inflationary cost adjustments since it would not serve any constructive purpose to present recalculations that would result in only a small expense adjustment. The Company utilized a CPI rate of 4.2% to make O&M inflation expense adjustments from the historical test year to 2023 expenses, a 2.7% rate to determine inflation adjustments for 2024 expenses, and a 2.4% rate, prorated to 1.8%, to determine 2025 inflation adjusted expenses for the nine months of 2025. Unlike prior rate filings, the Company has only applied the CPI rates to O&M expenses without including wage rate increases in a blended rate with the CPI rate. This change is welcomed and hopefully is permanent. In previous rate cases I advocated against the use of a blended inflationary adjustment to O&M expenses. The Commission agreed with my position, and I still hold that view.

B. Gas Line Staking & Locating Expense

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE GAS LINE STAKING AND LOCATING PROGRAM AND THE IMPACT ON FORECASTED O&M EXPENSE FOR THE PROJECTED TEST YEAR.

A. On line 9 of page 1 of Exhibit A-102 (JPP-2), the Company shows Staking expense increasing from $10.3 million in 2022 to $16.4 million for the projected test year for an increase of 59%. Beginning on page 40 of his direct testimony, Mr. Pnacek discusses the Staking and Locating program and on page 42 identifies the major drivers for the increase in expense. The largest increase at $3.1 million pertains to the expansion of the Gas Only locating program to other areas of the Company service area outside of Oakland County. Where typically gas, electric, and water utilities share the cost of locating underground facilities when Miss Dig is requested to locate underground facilities by customers, contractors, and other parties, in 2023, the Company began a program of staking only its own gas and electric facilities in Oakland County.

This change emanated from internal and external problems that the Company had in managing its staking and locating program in recent years. The Company-only dedicated staking and locating program in Oakland County was an experimental program to establish whether the incremental benefits justified the incremental cost of a dedicated program.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSED CHANGES TO THE GAS LINE STAKING AND LOCATING PROGRAM?

A. In his testimony, Mr. Pnacek tries to justify the dedicated Company-only program by the high volume of mislocates and untimely staking in Oakland County and other populous counties without adjusting the number of residents and developing ratios related to the number of locating requests received in those counties versus other counties. The data presented therefore is misleading and not sufficiently useful to make informed decisions.

Furthermore, the problems experienced by the Company with the shared staking and locating program are not being experienced by other gas and electric utilities in Michigan to require a separate dedicated and costly program.

The data gathered by the Company during the first year of operation of the Company only dedicated staking and locating program is still limited, but it shows that this program is at least twice more costly than the shared program. The information provided in response to DR AG-CE-0428 shows that the dedicated approach cost $2.8 million in 2023 to stake 64,235 locations in two-thirds of Oakland County, whereas the shared model for the remaining one-third of the county had 37,2010 staking locates at a cost of $951,000.[96] If we prorate the number and cost to be the comparable 64,235 locates in the dedicated program, the shared program cost would have been $1.6 million versus the dedicated cost of $2.8 million.[97]

Mr., Pnacek claims that the dedicated staking and locating program will increase public safety and on page 49 of his testimony he states that accuracy of at-fault damages improved by 85%, field timeliness improved by 1.4%, and the number of damages decreased by 26%. However, when looking at the underlying data supporting those percentages, the conclusions are based on very limited results over a short period of less than one year.[98] For example, the accuracy percentage is based on only 80 incidents in total and the basis to determine accuracy is not fully explained and appears to be subjective. The 26%

[96] Exhibit AG-65 includes DR AG-CE-0428.
[97] $951,088 ÷ 37,210 x 64,235 = $1,642,000.
[98] Exhibit AG-65 includes DR AG-CE-0160, 0161, 0162, and 0427.

reduction in the number of damages is actually 24.7%, but even this percentage of improvement shows that the dedicated program still resulted in 314 incidents of damage to underground facilities during the period that the dedicated program was in place in 2023. Such a result cannot be deemed a great success for the program and certainly does not justify the higher cost.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The data gathered by the Company to date is still preliminary and insufficient to justify expanding the Company-only dedicated staking and locating program to Kalamazoo, Ingham, and Kent counties. The cost is very high, and the benefits identified so far are marginal at best. Therefore, I recommend that the Commission remove the incremental O&M expense of $3.1 million included by the Company in the projected test year.

C. Gas Engineering and Supply

Q. PLEASE DISCUSS THE OVERALL ADJUSTMENTS THAT YOU PROPOSE TO THE GAS ENGINEERING FORECASTED O&M EXPENSE FOR THE PROJECTED TEST YEAR.

A. In Exhibit A-94 (KAP-1), the Company shows O&M expense for the Gas Engineering and Supply department of $13.9 million for the 2022 historical year increasing to $22.0 million in the projected test year. The areas within the department that show the largest increases are Gas Asset Management and Gas Engineering Support. In my testimony below, I will propose adjustments to the Project Management and Quality Lean Office, the Storage Integrity Management Program (SIMP), and other expense reductions for the recent corporate reorganization within the two major areas.

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO THE O&M EXPENSE FOR THE PROJECT MANAGEMENT AND QUALITY LEAN OFFICE.

A. In Exhibit A-94, the Company shows O&M expense for the Project Management and Quality Lean Office of $1,929,000 in 2022 declining to $1,635,000 for the projected test year. On page 12 of her direct testimony, Ms. Pascarello describes the responsibilities and activities of this department as providing project oversight and management for certain programs. The Quality Lean department assists in evaluating current enterprise-wide process improvements and continuous improvement opportunities.

In discovery, the Attorney General asked the Company to provide a list of the process improvements and work efficiencies achieved by the Quality Lean department during the past three years with the related cost savings and show where those cost savings have been included in exhibits in this rate case. In response the Company could not identify any initiatives or improvements made and any resulting cost savings.[99]

[99] Exhibit AG-66 includes DR AG-CE-0344.

The Company has not justified the value of spending more than $1.6 million on this function annually. Therefore, I recommend that the Commission remove the entire $1,635,000 of O&M expense from the projected test year.

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO THE O&M EXPENSE FOR THE SIMP.

A. On line 7 of page 2 of Exhibit A-95 (KAP-2), the Company shows the O&M expense for the SIMP increasing from $629,000 in 2022 to $5,341,000 in the projected test year. On page 18 of her direct testimony, Ms. Pascarello states that under new federal rules and industry guiding practices, the Company plans to undertake a more active program of inspections and remediations of gas storage facilities.

In response to discovery, the Company provided further details as to where the $5.3 million of forecasted expense will be spent on in the projected test year. The information provided in DR AG-CE-0348 shows some broad ranges of resources and costs that are planned to be deployed. One category of spending that is nebulous is Risk Reduction. The description for this cost category is reviewing records and evaluating risk. In the resource description, the Company admits that this cost could vary significantly requiring from 3 to 6 contractors. The forecasted cost for this planed activity is $2,265,000.[100]

The Company has not yet defined how it will complete these planned tasks and the actual resources that it will need. The forecasted expense is too preliminary and uncertain to

[100] Exhibit AG-67 includes DRs AG-CE-0348, 0349, and ST-CE-0109 with ATT 1.

include in O&M expense for the projected test year. Therefore, I recommend that the $2,265,000 be removed from O&M expense for the projected test year.

Q. PLEASE DISCUSS THE OTHER ADJUSTMENTS THAT YOU PROPOSE TO THE O&M EXPENSE FOR THE ENGINEERING AND SUPPLY DEPARTMENT.

A. In 2023, the Company implemented a corporate reorganization that resulted in the reduction of 404 employees, or full-time equivalents (FTEs), of which 161 FTEs pertained to the gas business. In response to discovery, the Company provided this information, as well the cost reductions by department.

As stated earlier, not all departments included the future labor cost savings in preparing their forecasted labor expense included in O&M expense for the projected test year. In the report provided by the Company in response to DR AG-CE-0341, the Gas Engineering and Supply department failed to include $1,067,000 of O&M savings for the projected test year.[101] I recommend that the Commission reduce the projected O&M expense by this amount.

In total, for the Gas Engineering and Supply department, I recommend that the Commission reduce O&M expense for the projected test year by $4,927,000. This includes the reorganization savings discussed above of $1,027,000, the lower SIMS cost

[101] Exhibit AG-68 includes DR AG-CE-0341 with attachment.

of $2,265,000, and the $1,635,000 of reduced Project Management and Quality Lean Office expenses.

D. Transmission Pipeline Integrity

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO THE GAS TRANSMISSION PIPELINE INTEGRITY FORECASTED O&M EXPENSE FOR THE PROJECTED TEST YEAR.

A. On line 4 of page 2 of Exhibit A-55 (MPG-1), the Company shows O&M expense for Pipeline Integrity - Transmission of $19.4 million for the 2022 historical year increasing to $22.6 million in the projected test year. In discovery, the Attorney General asked the Company to provide the historical and forecasted expense with related work units or projects completed in 2018 through 2023 and forecasted for 2024 and 2025.

The information provided by the Company shows that during the most recent three years (2021-2023), the Pipeline Integrity expense ranged from $9.6 million in 2023 to $16.2 million in 2021 with completed projects ranging from 41 to 57.[102] The average cost per project was $282,329. In WP-MPG-15, the Company provided the list of projects to be completed in 2024 and the related cost, showing 41 projects and total forecasted expense of $22,275,398. The cost per project for 2024 is $543,302, which is nearly double the average cost for the most recent three years. For 2025, WP-MPG-17 shows that the

[102] Exhibit AG-69 includes DR AG-CE-0271 with ATT 1.

Company forecasted 40 projects at a cost of $22,701,801 and an average cost of $567,545.[103]

The average cost per project for 2024 and 2025 is excessive and not supported in testimony. By applying the inflation factor of 2.6% to the three-year average cost of $282,329, I calculated a cost per project of $289,670 for 2024. Using this cost multiplied by the 41 projects planned by the Company, I arrived at total forecasted cost of $11,876,000 the year 2024, and $8,907,000 for the 9 months ending September 2024.

For 2025, I increased the 2024 cost per project by the inflation rate of 2.2% to arrive at a cost per project of $296,043. This amount multiplied by the 40 projects planned by the Company for 2025 results in a forecasted expense of 11,842,00. The expense for the 12 months ending September 2025 is $11,851,000. This amount is $10,733,000 lower than the amount forecasted by the Company of $22,584,000.

Therefore, I recommend that the Commission remove the $10,733,000 from the Company's forecasted O&M expense for the projected test year.

E. Information Technology Expense

Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO IT O&M EXPENSE.

A. On page 2 of Exhibit A-19 (SHB-3), the Company forecasted the projected test year O&M expense based on 2022 actual expense of $6,869,000. In response to discovery, the

[103] Id. Includes WP-MPG-15 and 17.

Company reported that 2023 actual O&M expense had declined significantly from 2022 to $4,375,000.[104] The difference between 2022 and 2023 is a decline in O&M expense of $2,494,000. This more recent expense level shows that the 2022 O&M base from which the Company forecasted the projected test year expense is no longer appropriate. The lower expense level needs to be reflected in the projected test year O&M expense.

Therefore, I recommend that the Commission remove $2,494,000 from O&M expense from the projected test year.

F. Uncollectible Accounts Expense

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

A. In Exhibit A-46 (MJF-3), page 2, the Company proposed $15.3 million of uncollectible accounts expense for the projected test year. However, there are two major problems with the Company's approach to estimating the projected test year expense. First, while the Company used the Commission approved method of developing a loss ratio based on a 3-year average of net charge-offs to revenue, it used the years 2018, 2019 and 2022 to develop the ratio instead of more recent years. On pages 9 and 10 of his direct testimony, Company witness Matthew Foster explains the use of these periods due to the alleged impact of the Covid-19 pandemic on 2020 and 2021 uncollectible costs. Mr. Foster's claim is that customers changed their bill payment habits due to the availability of federal

[104] Exhibit AG-70 includes DR AG-CE-0394 with ATT 1.

payments under the American Rescue Plan, while concurrently the Company suspended past due bill dunning action and gas service shut-offs, which would have the opposite effect of increasing past due amounts and uncollectible expense.

Second, gas prices projected for the projected test year, which are a component of the revenues for the test year, have fallen significantly since the Company filed the rate case. To compensate for this change, I have adjusted the forecasted revenue amount for the projected test year.

In response to discovery, the Company provided the 2023 uncollectible accounts charge-offs and revenues, thereby allowing an update to the net charge-offs to revenue ratio to more current data. As shown in Exhibit AG-61, I used the net charge-off to revenue ratio from the most recent three years from 2021 to 2023. This latest information increases the Bad Debt Loss Ratio from the 0.623% used by the Company to 0.646%, which is more favorable for the Company by increasing uncollectible expense. Additionally, I reduced the forecasted revenues for the projected test year by reducing the cost of gas component by $148 million due to lower forecasted gas prices.[105] This lowers the base on which uncollectible expense is calculated.

The result of my analysis is a forecasted uncollectible accounts expense of $14.9 million, which is $0.4 million lower than the Company's projection. Therefore, I recommend that

[105] DR SA-CE-102 provides revised cost of gas information based on NYMEX futures pricing in early February 2024.

the Commission remove $0.4 million from the Company's forecasted O&M expense for the projected test year.

G. Company Use & LAUF Gas Expense

Q. THE COMPANY'S PROJECTED TEST YEAR INCLUDES COSTS FOR COMPANY USE GAS AND LAUF GAS OF $6.4 MILLION AND $13.4 MILLION RESPECTIVELY. DO YOU AGREE WITH THESE PROJECTIONS?

A. No. The Company projected these costs based upon NYMEX gas futures prices for the projected test year which were determined in early September 2023. Since then, gas costs have declined substantially. In response to discovery, the Company provided updated forecasted gas prices for the projected test year as of early February 2024, which shows that NYMEX gas prices have fallen from $3.844 per MMBTU assumed in the rate case filing to $3.224 per MMBTU. Based on this information, I calculated a change in the cost of gas of $0.667 per Mcf.

In Exhibit AG-62, I applied the reduction in the cost of gas to reduce the O&M expense for both Company Use Gas and LAUF Gas by $3.4 million.

Q. DID YOU MAKE ANY OTHER CHANGES TO COMPANY USE AND LAUF GAS?

A. Yes. I reduced the LAUF volume by 342 MMCF which is 9.8% of the LAUF gas volume determined by the Company for the reasons explained below.

As discussed by witness Michael Stuart on page 7 of his testimony, the Company is pursuing a net zero methane emissions goal from its natural gas delivery system by 2030. He points to the Company's efforts to "…replace aging pipe, rehabilitation or retiring outdated infrastructure and adopting new technologies and practices."[106] Mr. Stuart also notes the federal government's goals of net-zero-emissions by 2050.

Given the significant expenditures by the Company involving infrastructure replacement, improved metering and regulators, it is reasonable to expect progressively lower LAUF gas volumes in the coming years. Although the Company's goal to achieve near zero emissions by 2030 may be overly ambitious, reaching the net-zero emissions by 2050 should be achievable. In this regard, the year 2050 is 28 years into the future from the 2022 historic test year. The average annual improvement over this 28-year period would be 3.57% (100% ÷ 28 = 3.57%). Multiplying this 3.57% reduction rate by the 2.75 years between the historical and projected test year in this rate case results in a 9.8% reduction in LAUF gas volumes by the projected test year.

This 342 MMCF adjustment multiplied by the $3.197 per MCF cost of gas lowers LAUF gas costs by $1.1 million.

[106] Michael Stuart direct testimony at page 7, lines 18 to 23.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION FOR COMPANY USE AND LAUF GAS EXPENSES IN THIS CASE.

A. I recommend that the Commission reduce the expense for Company Use and LAUF gas by $4.5 million. This includes the cost savings of $3.4 million due to a lower cost of gas rate and the $1.1 million related to lower LAUF volumes.

H. Active Health Care Expenses

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

A. Line 4 of Exhibit A-66 (KKG-1) shows actual health care, life insurance and disability (Health Care & Other) expense of $16.0 million for 2022 and $17.7 million for the projected test year for an increase of approximately 10.6% over the nearly three-year period.

Beginning on page 20 of her direct testimony, Company witness Kendra Grob describes several reasons for the increase in health care costs. Witness Grob escalated 2022 expenses by the CPI rates of 4.2%, 2.7% and 2.4% for the years 2023, 2024 and 2025, respectively, and then further increased the result by $0.4 million as shown on Exhibit A-66 (KKG-1) page 2. The result is an average inflation rate of approximately 4.0% which I find reasonable. However, the Company failed to adjust its projected results for the reduced headcount resulting from the 2023 corporate reorganization.

Q. WHAT IS YOUR PROPOSED ADJUSTMENT TO HEALTH CARE EXPENSE FROM THE EMPLOYEE REDUCTIONS?

A. While the Company's medical inflation rate is reasonable, Exhibit A-66 makes no adjustment for the Company's headcount reductions. In Exhibit AG-63, I first used the actual Health Care & Other costs from 2017 to 2022 provided by the Company to determine the actual trend in costs. Costs over the historical period increased by approximately 4.1% annually for the total Company's gas and electric employees between 2017 and 2022.

The 4.1% average rate of increase results in a proforma forecast expense of $17.9 million for the forecasted test year before applying the reduction in the number of employees. I calculated that the employee downsizing in 2023 resulted in an 8.5% reduction in the number of employees.[107] By applying the 8.5% reduction to the projected proforma test year expense of $17.9 million, I determined that the employee downsizing program at the Company should lower health care costs by $1.5 million.

Therefore, I recommend that the Commission reduce the Company's Active Health Care expense forecast in this rate case by $1.5 million.

[107] Page 34 of the Company's 2023 Annual Report on Form 10-K filed with the SEC shows employee levels for total Company of 8,897 in 2022 and 8,144 in 2023 which is an 8.5% reduction.

I. Employee Savings Plan Expense

Q. THE COMPANY FORECASTED 401(K) EMPLOYEE SAVINGS PLAN EXPENSE OF $7.6 MILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE FORECASTED AMOUNT?

A. No. The forecasted expense amount does not take into consideration the Company's corporate reorganization and employee downsizing and needs to be adjusted. In discovery, the Company provided the actual 401K expense for 2023, which shows that the actual expense declined by $0.8 million to $6.4 million from forecasted amount of $7.2 million for 2023.[108] This reduction is consistent with the Company's headcount reduction of 8.5% discussed previously.

In Exhibit AG-64, I show the calculation for a revised expense amount of $6.7 million for the projected test year. The calculation starts with the 2023 actual expense and applies the inflation rate for 2024 and 2025. The resulting amount of $6.7 million when compared to the Company's forecast of $7.6 million results in a proposed reduction in expense of $0.9 million.

I recommend that the Commission reduce the Company's expense amount for the projected test year by $0.9 million.

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[108] DR AG-CE-401.

J. Corporate Services and Other Expenses

Q. ARE YOU PROPOSING OTHER O&M ADJUSTMENTS THAT RESULT FROM THE COMPANY RECENT CORPORATE REORGANIZATION AND EMPLOYEE DOWNSIZING?

A. Yes. As stated earlier in response to discovery seeking information on cost savings from the recent corporate reorganization and employee downsizing, the Company provided a schedule showing those departments within the Company that had not reflected O&M expense savings in the projected test year. In addition to the Engineering and Supply department, which I addressed earlier, the Company disclosed that the following areas had not included cost savings in the projected test year:

1. Gas Operations $0.615 million
2. Corporate Services $3.136 million
3. Fleet Department $0.068 million

The total amount from the three departments is $3,819,000. I recommend that the Commission remove this amount for the Company's projected test year O&M expense.

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO O&M EXPENSE FOR THE PROJECTED TEST YEAR?

A. Yes. As discussed above in the capital expenditures section of my testimony, some of the projects has O&M expense that should also be removed from the projected test year in conjunction with removal of capital expenditures discussed above. Additionally, I proposed that the lease payments pertaining to the five facilities supporting the EIRP be removed from O&M expense. These expense disallowances total to $2,245,000 and are listed below:

1. Asset Accounting Upgrade and Customer Order Tracker ($236,000)
2. Customer Work Request Web Portal ($119,000)
3. Gas Compression Historian ($133,000)
4. Tracking and Traceability system ($500,000)
5. Security systems ($196,000)
6. EIRP Facilities leases ($1,061,000)

I recommend that the $2,245,000 of expense pertaining to these projects be removed from the projected test O&M expense.

Therefore, in total for Corporate Service and Other, I recommend that the Commission remove $6,064,000 of O&M expense from the project test year.

K. Incentive Compensation Expense

Through the testimony of witnesses Amy Conrad and Michael Stuart, the Company proposes to recover in rates nearly $1.5 million of short-term incentive compensation.[109]

In the following pages of my testimony, I will analyze the Company proposal to include in rates the cost of incentive compensation and the alleged benefits to customers provided by Mr. Stuart in his testimony. Over the past few years, the Company has made several changes to the incentive plan that have made it easier for the Company to payout incentive

[109] Exhibit A-42 (AMC-3).

compensation. For example, the operating performance measures that drive the short-term incentive payouts under the plan were revamped since gas rate Case No. U-20650 and electric rate Case No. U-20697. Beginning in 2022, the ability to trigger a payout has been modified to make it much easier for employees to receive incentive compensation payments. I will discuss these changes in more detail later in my testimony.

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

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

The major components of the EICP for non-officer employees are shown in Exhibit A-40 (AMC-1). Fifty percent (50%) of the target award in 2022 was based on achieving 10 performance measures related to employee safety, customer experience, electric reliability, affordability, as well as employee empowerment and methane reduction. In prior years, to achieve 100% payout of this grouping of "operating" measures, the Company needed to only achieve 6 performance measures. The other 50% of the target award was based on achieving earnings per share and operating cash flow goals of CMS Energy. The two items had 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. Over the last five years, non-officer employees have received incentive payouts as a percentage of target of 123% in 2018, 111% in 2019, 139% in 2020, and 77% in 2021 and 117% in 2022.[110] The only year in the past fourteen years where a bonus payout was not made to non-officer employees was in 2011 when only 6 of the 11 operating measures were achieved. These consistent payouts indicate that incentive compensation is not at-risk compensation based on achieving superior performance, but it simply supplements base pay.

For the officers' EICP, the target payout has been based almost entirely on earnings per share and operating cash flow. However, the percent payout can be adjusted up or down depending on whether there is a payout related to the operating measures.

In forecasting the amount of EICP expense of $1.5 million included in the forecasted test year, the Company assumed that a 100% payout (at target) for both the officer and non-officer EICP will occur.

Q. HAS THE COMPANY MADE ANY CHANGES TO THE EICP FOR 2022 PAYOUTS?

[110] DR AG-CE-165 with attachment.

A. Yes. In their direct testimony, Ms. Conrad and Mr. Stuart discuss how the requirements of the EICP were modified effective in 2022. First 30% of the payout for officers is directly linked to the operational measures, whereas in the past the operational measures have been characterized as a "modifier."[111] Also, the requirement that a minimum number of metrics need to be achieved at threshold level and at target level to trigger a payout has been dropped.[112] Instead, each individual metric will have its own threshold and target payouts.

These changes may focus greater officer interest on certain operational metrics, but it virtually assures an incentive payout even if only one operational metric is achieved since there is no minimum number of performance metrics to be achieved to trigger a payout as in the past.

Q. PLEASE PROVIDE A SUMMARY OF RECENT CHANGES MADE TO THE EICP METRICS THROUGH 2022.

A. A review of Exhibit A-32 (AMC-1) from Case No. U-20650 shows the operating performance measures previously included a customer experience index, a customer on-time delivery measure, and a service on-time commitment metric. These later two performance metrics have been dropped and only the customer experience index remains. As for employee-related performance metrics, the employee safety metric continues, and the Company has added an employee empowerment metric. Also, the previous metric

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[111] U-20650 testimony of Ms. Conrad on page 22 (lines 15 and 16).
[112] Case U-21148 Exhibit AG-52 includes DR AG-CE-0097.

related to replacing vintage services has been dropped and a new metric has been added which is methane reduction from repairing/replacing leaking gas pipes.

Q. WHAT IS YOUR ASSESSMENT OF THE CHANGES TO THE PERFORMANCE MEASURES?

A. The previous customer-related performance metrics were somewhat redundant, so going with one overall satisfaction metric is a positive change. As for adding the methane emission reduction metric, this new metric may make sense from an overall corporate viewpoint. However, it is questionable if it belongs within the employee performance metrics. Most employees have little impact on achieving that metric.

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.

For the 2022 plan cycle, half of the non-officer employee EICP payouts and 70% of the Officer EICP payouts were dependent upon the financial metrics. As such, the officer group that sets the direction of the Company is still 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 has not issued any significant common stock in more than five years. 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 past, the Company had to achieve at least a minimum number of operating metrics to trigger an incentive payout. Although, the number of operating metrics to be achieved was relatively low to demonstrate exceptional performance even that minimal requirement has now been dropped. Therefore, even mediocre performance will be rewarded if only a single metric is achieved. 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 gas customers subsidize other businesses, particularly non-utility operations.

Lastly, the Company has stated that it continues to pay salary increases each year of approximately 3.2%.

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 three of the operating performance measures that are part of the EICP. In Exhibit A-111 (RMS-2), Mr. Stuart shows the number of Safety Incidents, which were 105 in 2019 and 107 in 2022. The exhibit also shows that the Company's 2022 Workers Compensation and other related costs have increased by approximately 34% since 2019 to $2.8 million. Clearly, these results do not show superior performance or an improving trend.

In Exhibit A-112 (RMS-3), Mr. Stuart shows the Company's SAIDI Index results as a measure of Electric Reliability. The 170 achieved index for 2023 compares well to the 2021 results of 238, but results in past years have been erratic with no consistent trend of improvement.[113] Therefore, the claimed $37.8 million of savings based on the Berkley Labs formula are suspect.

Mr. Stuart also calculates certain savings related to the Company's Culture Index based on purported cost savings from lower employee turnover. However, Exhibit A-113 shows that employee turnover was 2.5% in 2022 compared up from 2.0% in 2021 and 1.1% in 2020. Clearly, this is not an improving trend.

[113] In U-21308, Mr. Stuart's Exhibit A-100 shows a SAIDI result for 2018 of 180 with results increasing in the 2019 to 2022 period.

In summary, the cost savings calculated by Mr. Stuart are inconsistent with recent trends in performance, speculative and at best transitory. They do not justify the $1.5 million of incentive compensation that the company seeks to recover in this rate case.

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

The Company's proposed incentive compensation expense of $1.5 million for the projected test year assumes that the Company will achieve target performance for all its goals. There is no track record with the revised performance measures that supports that conclusion. It is probable that the Company may fall short of achieving 100% of the performance measures. In response to discovery, the Company stated if it achieved only the lower threshold level of performance that the incentive compensation would be $754,000 for the projected test year.[114]

Although I do not believe the Company has made a compelling case to justify recovery of any amount of incentive compensation and therefore no incentive compensation should be included in rates. In recent rate cases the Commission has approved a portion of incentive compensation pertaining to operating measures and if it decides to do so in this case, I recommend that the Commission approve at most recovery of the $754,000 incentive compensation amount related to potential achievement of operating measures at the threshold level and remove the remaining $0.8 million from O&M expense for the projected test year.

[114] Exhibit AG-72 includes DR AG-CE-165.

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 ($ Millions)
Gas Distribution	$ 3.1
Gas Engineering	4.9
Gas Transmission	10.7
Information Technology	2.5
Company Use and Lost Gas	4.5
Health Care Costs	1.4
Corporate Expenses and Other	8.2
Total	$ 35.3

I recommend that the Commission reduce the amount of total O&M costs proposed by the Company by $35.3 million and reduce the revenue deficiency accordingly. Exhibit AG-60 provides further details.

XI. Adjustments To Revenue Deficiency

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

A. Exhibit AG-71 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $5.3 million, which is a reduction of $130.7 million from the Company's requested level of $136.0 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $5.3 million.

XII. Sale of Appliance Service Program

Q. PLEASE DISCUSS THE SALE OF THE APPLIANCE SERVICE PROGRAM AND THE COMPANY'S PROPOSED SHARING OF THE NET PROCEEDS WITH CUSTOMERS.

A. On April 11, 2024, the Company announced that it sold its Appliance Service Program (ASP) to Oncourse Home Solutions. The transaction had been in the works for several months and in preparing testimony in the current rate case the Company incorporated certain aspects of the transaction in its filed testimony and exhibits, albeit on a confidential basis. The transaction included other small businesses under the Home Energy Products Program, but the ASP represented nearly 100% of the sale transaction.

Although the Company did not disclose the final price, it proposed that it would share 50% of the net proceeds after transaction expenses with customers over a five-year period through a bill credit. The credit would also include certain fees received from the buyer net of expenses incurred by the Company to provide on-going services to the buyer, such as customer service and billing expenses. According to the recently unredacted testimony of Ms. Heidi Meyers, the Company proposes to provide an annual bill credit over five years of $14,007,000, consisting of $12,200,000 from the net sales proceeds and $1,807,000 from the on-going annual fees net of costs for the first year subsequent to the effective date of the credit.[115] This second part of the credit is likely to diminish over time.

Q. WHAT IS YOUR ASSESSMENT OF THE SALE TRANSACTION AND THE SHARING PROPOSED BY THE COMPANY?

A. It is best to begin with an historical perspective to guide the Commission's decision on the proposal. The Company started the predecessor program to the ASP in 1988. Like other gas utilities, the Company used available utility field service employees to perform house calls and visits to small businesses to repair furnaces, water heaters, and other appliances. The services were marketed as an extension of the utility business and funded through utility rates. The revenue collected offset the expenses of the program and often create a net margin above costs. The Company used the utility's name and brand to market the appliance repair services, the customer call center, and other utility resources. Still today,

[115] Heidi Myers's Revised Direct Testimony at page 11.

the Company relies on those utility assets to market and service the ASP and to some degree will continue to do so after the sale of the program to Oncourse Home Solutions.

At some point on or around the year 2000, the Company began to use a network of contractors to do the bulk of the repairs with some significant involvement still by utility field employees. At around this time, the Company began to consider the program an unregulated business under Value Added Services. Although the prices charged to utility customers for appliance repair services were not set by the Commission, the utility continued to fund the costs of the program through utility rates and passthrough the revenue collected to utility customers in setting utility rates for the Company. For all practical purposes, the ASP continued to be part of the utility operations of the Company but operated in a fashion that any costs incurred by utility employees pertaining to operation of the program needed to be fully allocated to the program for proper accounting and to avoid cross cost subsidies by utility customers. These requirements were further reinforced in the adoption of the Code of Conduct for transaction between utility operations and non-utility operations for all Michigan utilities subject to the Commission's jurisdiction.

Q. CAN YOU PROVIDE THE AMOUNT OF GROSS PROFIT THAT THE ASP HAS GENERATED IN THE PAST FIVE YEARS AND WOULD LIKELY GENERATE IN THE PROJECTED TEST YEAR IF A SALE HAD NOT OCCURRED?

A. Yes. In the last gas rate case U-21308, I prepared testimony, based on information provided by the Company, showing that the ASP was generating gross profit margins (revenue in excess of fully allocated costs) of $14 million to $30 million annually between 2017 and 2022. A copy of the Company response to discovery request U-21308 AG-CE-0457 is included in Exhibit AG-73. For 2023, the Company reported an actual gross margin of $16.5 million.[116]

Q. DO YOU FIND THE COMPANY'S PROPOSAL TO SHARE 50% OF THE NET PROCEEDS FROM THE SALE OF THE ASP WITH UTILITY CUSTOMERS JUST AND REASONABLE?

A. No. Up to the sale of the ASP, utility customers received 100% of the net revenue benefits of the program, which of late have exceeded $15 million annually and would continue to do so <u>past the five-year period of the Company's proposed sharing</u>. Through the sale of the program in effect the Company is monetizing the future value that customers would have received and is keeping 50% of those future values. The result is not just and reasonable. If the Company wants to end its involvement with the ASP, then 100% of the net proceeds of the transaction and the on-going net benefits need to be passed through to customers. Any sharing of those proceeds would put customers at a disadvantage and remove benefits previously received.

Utility customers have funded the ASP since its original launch and through utility rates collected by the Company have made it possible for the Company to grow the program and use the brand name built over decades by the utility operations of the Company. For

[116] DR AG-CE-0243 Revised with attachment.

the Company now to take a position that the ASP is a non-regulated business, and it should receive 50% of the net proceeds from the sale of the program is not a just and reasonable outcome and should not be accepted by the Commission.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission order the Company to passthrough to utility customers through a bill credit 100% of the net proceeds from the sale of the program, which at this point, based on preliminary information, is $24,400,000, plus the on-going net fees of $1,807,000 during the first year, for a total bill credit of $26,207,000. Furthermore, the Company needs to provide a final accounting of the transaction either as an addendum to this rate case subsequent to a Commission order or in the next rate case, showing the final price and costs of the transaction, including any subsequent sale price adjustments and earn-outs, transition cost reconciliation, and on-going annual fees and cost adjustments to be refunded to customers through the bill credit.

XIII. Rate Design

Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR RESIDENTIAL CUSTOMERS HAS THE COMPANY PROPOSED?

A. In his direct testimony, Company witness Austin Smith proposes to increase the monthly service charge for residential customers from $13.60 to $18.60 per month. According to his testimony, the proposed monthly service charge reflects a rate of increase considerably less than the actual customer-related fixed costs calculated in the Company's cost of service study.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The proposed change from $13.60 to $18.60 per month represents an increase of 37%. Such a large increase could cause financial hardship to customers in smaller households who use less gas than the average customer. They would see their monthly gas bill increase without using any more gas. Fixed monthly charges also discourage energy conservation. It is best to increase the volumetric rate paid by customers because the higher cost encourages conservation. The customer can take steps to reduce usage and thus lower the gas bill. The customer cannot reduce fixed monthly charges.

Q. WHAT DO YOU RECOMMEND?

A. I recommend keeping the residential customer monthly charge at $13.60. or at most increasing it by $1 to $14.60.

Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR GENERAL SERVICE GS-1 CUSTOMERS HAS THE COMPANY PROPOSED?

A. In his direct testimony, Mr. Smith proposes to increase the monthly service charge for customers on Rate GS-1 from $16.00 to $19.00 per month. Although not stated directly in his testimony, it appears that the proposed monthly service charge for this rate schedule also reflects the actual fixed costs calculated in the Company's cost of service study.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The proposed change from $16.00 to $19.00 per month represents an increase of 19%. Such a large increase could cause some hardship to customers with smaller businesses who use less gas than the average commercial customer. They would see their monthly gas bill increase without using any more gas. As stated above, fixed monthly charges also discourage energy conservation. It is best to increase the volumetric rate paid by customers because the higher cost encourages conservation. The customer can take steps to reduce usage and thus lower the gas bill. The customer cannot reduce fixed monthly charges.

Q. WHAT DO YOU RECOMMEND?

A. Again, in the interest of rate gradualism, I recommend that the Commission should increase the GS-1 monthly charge by no more than $1 to $17.00 and preferably keeping it at $16.00.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

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

Experience and Qualifications of Sebastian Coppola

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

EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for 22 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

ENERGY INDUSTRY EXPERTISE

During his 27-year career at SEMCO Energy, MCN Energy and MichCon, Mr. Coppola held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

Mr. Coppola is intricately knowledgeable of capital markets and financial institutions. As Treasurer and Vice President of Finance, he directed the issuance of more than $2 billion in securities, including common stock, corporate bonds, tax-deductible preferred stock and high-equity value convertible securities. He established bank lines of credit, commercial paper and asset acquisition facilities. He has had extensive interactions with equity and debt investors, financial analysts, rating agencies and other members of the financial community.

ENERGY INDUSTRY AND REGULATORY EXPERIENCE

As a business consultant, Mr. Coppola specializes in financial and strategic business issues in the fields of energy and utility regulation. He has more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. He has testified in several regulatory proceedings before State Public Service Commissions. He has prepared and/or filed testimony in electric and gas general rate case proceedings, power supply and gas cost recovery mechanisms, revenue and cost tracking mechanisms/riders, multi-year rate plans and incentive ratemaking, and other regulatory matters.

Mr. Coppola has extensive experience with gas and electric utilities in the areas of gas operations, gas supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared

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testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General, the Maryland Office of Public Counsel, and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, DTE Electric Company, MichCon (DTE Gas Company), Michigan Gas Utilities Corp, Nicor Gas, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company, Washington Gas, and Wisconsin Public Service Company.

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

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

Experience and Qualifications of Sebastian Coppola

During his long career at DTE Gas, among other responsibilities, Mr. Coppola was responsible to oversee the operation of the MichCon Wet Header System, a pipeline that transported natural gas and gas liquids from Michigan gas producing fields in the Niagaran Reef in the northern area of the lower peninsula of Michigan to processing plants in Kalkaska, MI. His responsibility included ensuring the day-to-day flow of gas and liquids, and identifying operating issues requiring corrective action.

He was also responsible for the study to assess the feasibility of building the Saginaw Bay Pipeline, a transmission line to move Praire Du Chein natural gas reserves in the eastern area of Michigan to processing plants. Prior to the construction of the pipeline, Mr. Coppola worked with operating management to prepare requests for proposal for the construction project and the selection of qualified bids. During and subsequent to the construction of the pipeline, Mr. Coppola assisted in the management and oversight of the pipeline, including review of operating performance and profitability.

Additionally, as Manager of Materials Inventory, Warehousing and Procurement at DTE Gas, Mr. Coppola worked closely with suppliers of pipe, control valves, flanges, meters, fittings, equipment and thousands of other parts and materials used in the construction, repair and maintenance of DTE Gas's transmission, distribution and storage facilities, including repairs and upgrades to compressor stations, and replacement of cast iron mains, bare and wrapped steel pipelines and service lines. His responsibilities included the review of design and construction blueprints and plans with frequent visits to construction sites during excavation of new pipeline trenches, and during replacement of defective or leaky

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pipes, and replacement of control valves. Mr. Coppola also made frequent visits and inspection to storage facilities owned by DTE Gas to understand materials requirements during planned construction projects. Mr. Coppola was also responsible to ensure that materials and equipment were ordered to meet material standards and safety codes.

Through these responsibilities, Mr. Coppola gained knowledge and expertise with field construction project procedures, pipeline trenching problems, installation inspections, operation and maintenance cycles, and the material procurement of pipe, valves, flanges, meters and thousands of other parts and equipment used in the construction of natural gas transmission, distribution and storage facilities.

During his career with MCN Energy Group, Mr. Coppola was responsible for the evaluation of investments in interstate pipelines, new gas storage facilities, gas cogeneration plants, and construction of new power plants in the U.S. and India. Mr. Coppola was a key member of the negotiating team with contractors and suppliers tasked to build the power facilities, including the evaluation of Engineering, Procurement and Construction (EPC) bids and contracts.

Subsequent to his move to SEMCO Energy Corporation in 1999, Mr. Coppola was responsible for the acquisition and integration of pipeline construction companies providing services to gas utilities and interstate pipelines. In addition to its gas utility business in Michigan and Alaska, serving approximately 350,000 customers, SEMCO Energy owned SEMCO Pipeline Construction, a non-regulated business providing gas pipeline and natural gas facilities construction services to gas utilities and interstate pipelines in the Midwest and Eastern regions of the U.S.

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SEMCO Pipeline Construction provided construction services similar to KS Energy, Northern Pipeline and other contractors used by the Company. During his tenure at SEMCO Energy, Mr. Coppola reviewed dozens of pipeline construction companies and acquired six companies. Mr. Coppola's responsibilities included management of the performance and profitability of the pipeline construction services business requiring field visits to construction projects and quality reviews. In this process, Mr. Coppola learned firsthand how pipeline construction companies operate, construction project challenges, their bidding practices and the bidding of construction projects, including pricing, bidding procedures and policies both from the contractor's side and the gas utility side.

Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

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

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

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Mr. Coppola performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, he has performed analysis of power costs and filed testimony in power supply cost recovery cases, including reconciliation of annual power supply costs.

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

- **Specific Regulatory Proceedings and Related Experience:**
  - Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
  - Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
  - Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2022-2023 GCR plan in case No. U-21067.
  - Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2023 PSCR reconciliation in case No. U-21049.
  - Filed testimony on behalf of the Michigan Attorney General in Indiana Power Company 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

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- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023 GCR plan case No. U-21062.

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- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Act 9 application in Case No. U-20993 by Saginaw Bay Pipeline Company to set transportation rates for services to DTE Gas Company.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 electric rate Case U-20836 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed rebuttal testimony on behalf the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gaslight & Coke Company (Peoples Gas) in Docket 17-0137.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan reconciliation case No. U-20554.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2020-2021 GCR plan reconciliation case No. U-20552.

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- Filed testimony on behalf of the Michigan Attorney General in MGUC 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR plan reconciliation case No. U-20236.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Ameren Illinois Company (Ameren) in Docket 20-0323.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan case No. U-20822.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 PSCR plan case No. U-20802.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of

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People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.

- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.
- 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.

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- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2017-2018 GCR Reconciliation case U-20078.

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- Filed testimony on behalf of the Michigan Attorney General in CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.

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

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- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 gas general rate case U-18124 on a several issues, including

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revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.

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

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CECo Gas Choice and End-User Transportation tariff changes case U-17900.
- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- 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.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.
- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR plan case U-17317.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CECo's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in

Experience and Qualifications of Sebastian Coppola

Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CECo's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.
- Filed testimony in MichCon's 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors' compensation in the 2012 Avista general rate case.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio's power supply restructuring case in June 2012.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation's 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo's electric business Pilot Revenue Decoupling Mechanism in case U-16566.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.
- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.

Experience and Qualifications of Sebastian Coppola

- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the "Massachusetts Formula" at MichCon and at SEMCO in 1975 and 2000.
- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.
- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

EDUCATIONAL BACKGROUND

Experience and Qualifications
of Sebastian Coppola

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


CMS ENERGY
Leading the
CLEAN ENERGY
TRANSFORMATION
2022 Year End
Results and Outlook
February 2, 2023

Financial Results & Outlook . . .

2022 Full-Year Results	Amount	Commentary
Adjusted EPS	$2.89	High end of guidance

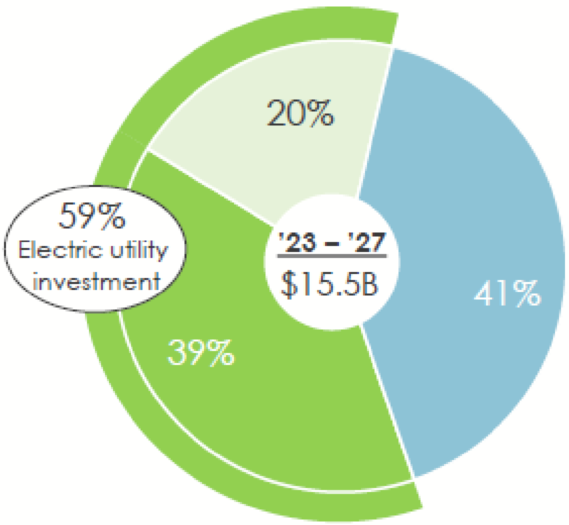
2023 Full-Year Outlook		
Adjusted EPS Guidance	$3.06 – $3.12	Toward the high end
Annual Dividend Per Share	$1.95	Up 11¢

Long-Term Outlook		
Adjusted EPS Growth	+6% to +8%	Toward the high end
Dividend Per Share Growth	+6% to +8%	Committed to growth
5-yr Capital Plan ($B)	$15.5	Up $1.2

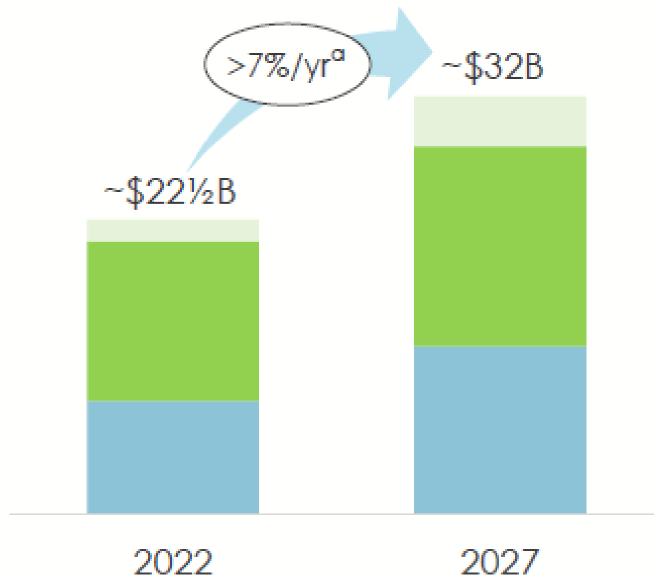
Updated Customer Investment Plan . . .

CMS ENERGY

New Utility Investment Plan



Rate Base Growth



Other Growth Drivers[b]

- ✓ EWR incentives
- ✓ FCM on PPAs
- ✓ 10.7% wind RPS
- ✓ NorthStar

Clean Energy Generation | Electric Distribution & Other | Gas Utility

~40% of investments support the Clean Energy Transformation

Presentation endnotes are included after the appendix.

Credit Metrics Maintained . . .

Consumers Energy	S&P	Moody's	Fitch
Senior Secured	A	A1	A+
Commercial Paper	A-2	P-2	F-2
Outlook	Stable	Stable	Stable
CMS Energy			
Senior Unsecured	BBB	Baa2	BBB
Junior Subordinated	BBB-	Baa3	BB+
Outlook	Stable	Stable	Stable
Last Review	✓ Oct. 2022	✓ May 2022	✓ Jan. 2023

Ratings Drivers

- Strong financial position
- Growing operating cash flow
- Constructive return on regulated investment
- Supportive regulatory environment
- Lower business risk

Deutsche Bank
Research

Rating
Buy

North America
United States

Industrials
Utilities and Power

Company
CMS Energy

Reuters	Bloomberg	Exchange	Ticker
CMS.N	CMS UN	NYS	CMS

Date
24 June 2018

Company Update

Price at 22 Jun 2018 (USD)	45.44
Price target	50.00
52-week range	50.55 - 41.77

Premium regulated grower cranks up the energy transition dial

Valuation & Risks

Jonathan Arnold
Research Analyst
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Caroline Bone, CFA
Associate Analyst
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Key indicators (FY1)	
ROE (%)	14.3
ROA (%)	2.8
Net debt/equity (x)	218.6
Book value/share (USD)	16.94
Price/book (x)	2.7
Net interest cover (x)	3.1
EBIT margin (%)	19.3

Source: Deutsche Bank

Top tier growth, execution ... and now top-tier low-risk energy transition

We spent last week visiting investors in Europe with the CMS team including CEO Patti Poppe and CFO Rejji Hayes. With a consistent and high-quality regulated growth story, accounts in Europe remain very receptive to the CMS story. Not much has changed here with the (still relatively) new management team articulating a by now very familiar message. New information at the margin was the inaugural integrated resource plan (IRP) filing under the 2016 Michigan energy law. The IRP proposes a complete exit from coal generation by 2040, a very significant (6GW) solar component by the later years and - perhaps most surprisingly - no new gas-fired generation. This further "greening" of the electric utility outlook offers incremental appeal for an ESG-focused client base, while we also sensed growing interest from some generalists in adding defensive US utility exposure given an uncertain macro backdrop and lower valuations in the group. From our perspective CMS remains a core US utility holding offering superior earnings growth along with exceptional visibility and execution. Attractive energy transition thematics are also on offer, but with below-average risk based on the opportunity to replace aging coal and out-of-market PPAs with utility-owned renewables. We remain Buyers of the stock with a $50 price target based on a 15% premium to our base regulated target multiple of 16.5x on our 2020E ($2.65).

World class performance, hometown service, home team advantage

CEO Patti Poppe often talks about the CMS commitment to Lean operating principles keying off more competitive businesses, notably the auto sector. These have allowed CMS to marry "world class performance" with "hometown service". Hometown advantage was clearly in play last week with local teams generally winning their World Cup games when CMS were in town. World Cup fever aside, overall messaging for investors continues to resonate well, with management offering plenty of real world examples to support their overall business model. Central to the model is continued pursuit of cost savings (2-3% net per year) which allows for targeted 6-8% earnings growth while still keeping customer rates at or below the rate of inflation.

Investment plan skewed to networks, replacing aging, expensive supply

A common question in several meetings was the nature of CMS's current mix in terms of the capital spending plan. Some seemed surprised by the fact that roughly half of the $10B 5-year capital plan is going to gas infrastructure, with gas rate base expected to grow from 30% of a $15B total number to 40% of a $21B number by 2022. Previously CMS have provided an overall $18B number for their 10-year capital plan, although for the last several investor presentations the specific 10-year number has been replaced with a longer-term opportunity pegged at >$50B. When or whether management will articulate a specific higher 10-year number they have made it clear that tax reform created around 4% of rate headroom on the customer bill, with a rule of thumb that each 1% opens up the potential for $400M of additional capital investment. One element of the forward plan we find particularly notable is the extent to which the current supply mix offers potential for CMS to replace non-return earning PPAs (MCV and Palisades) with utility-owned supply or other earning infrastructure investments in the networks. This is a major feature of the newly filed IRP, although the proposal is considerably more solar-centric than we might have expected as discussed further below. We see this expensive supply replacement component to be a differentiating feature of the CMS story versus most regulated peers, and one offering a path of less resistance in terms of continuing to deliver above-average growth with below-average inflation on the customer bill.

Recent IRP in focus … lots of solar, no new gas, no mention of DIG

Most of last week's meetings spent a good proportion of time on the recently filed Integrated Resource Plan (IRP). This is the first such plan filed under requirements established by the updated 2016 energy law. CMS ran over 350 iterations of the plan to find the optimal solution considering the current supply portfolio, forecast needs and expectations around costs for different potential supply options. The fact that there is no new gas-fired capacity proposed in the plan appears to indicate that management is no longer proposing to move the currently non-regulated DIG gas plant into a regulated construct. This had been part of the proposal to buy out the Palisades nuclear PPA early, which did not move forward last year after the PSC rejected the proposed terms. Similarly, another implication of the IRP as filed is that the PPA with the privately owned MCV plant may simply be allowed to step down and expire rather than being extended or otherwise restructured. The shift in plan here is essentially a reflection of CMS already having two large gas plants on the system (Zeeland and Jackson) along with the 2,200MW Luddington pumped storage facility. Between them management see these plants as sufficient to serve the utility's future baseload demand. And with baseload essentially covered by gas and Luddington, the utility's summer peak needs line up well with the summer-peaking Michigan solar resource.

Solar additions mostly come later … once coal fleet retires

Several questions were asked on where CMS would plan to site such a large solar build over time with the primary focus likely to be commercial rooftops rather than residential or greenfield. While it is clear that specific sites have not been pre-identified - at least not at a large scale - CMS seems confident that the area required would be relatively inconsequential in the context of the state as a whole (barely 0.5% of the state's total land mass). In addition the solar build is clearly somewhat far out in a plan which runs out through 2040, with even the $3B included in the current 10-Year financial plan mostly back-end loaded and likely beyond our current forecasting horizon.

Current solar pricing assumed with ~35% declines over the IRP period

Regarding pricing assumed in the IRP, the company's modeling uses "current" pricing in the ~$80/MWh range and assumes that prices will drop by ~35% from there over the course of the plan. Recent unsolicited bids in the ~$65/MWh range lead CMS to believe that their assumptions will likely prove to be conservative over the course of the plan. One appeal of solar from management's perspective is that it avoids large commitments to single units, which they view as inefficient given uncertainties over the future trajectory of load growth. From the CMS perspective the ability to add capacity in small bite-sized amounts is less risky

CMS Energy (CMS): Same old story, confidence in plan

- CMS didn't have much new to say, but the same level of confidence in its high growth plan is still there. Recently there has been a lot of focus on the Michigan regulatory environment and there appears to be some level of regulatory fatigue. The companies are filing rate cases frequently, and tax reform and the new energy law have created additional filings. That said, Michigan believes the sensitivity to allowed ROE changes is relatively manageable (10bps = $0.02 across electric and gas).
- The plan to deal with this regulatory fatigue is to pursue more tracked investment that might reduce the need for more frequent rate case filings. The company filed its latest electric rate case last week and is expecting a gas order later this year. The hope is that the rising interest rate environment stops the bleed lower in allowed ROEs.
- The other big focus area for the company is its upcoming IRP filing expected June. This will lay out a variety of scenarios for the future capital spend for years to come. The company is very focused on shifting from coal and towards more renewables. Additionally, the roll-off of high cost PPAs (Palisades, MCV) will also create investment opportunities. There is no shortage of potential for capital deployment and tax reform has helped to create additional headroom in customer rates.

CenterPoint (CNP): All things VVC

- CNP's decision to acquire VVC dominated the majority of our discussion. On the merger, mgmt. noted they have not yet identified specific synergy buckets, but rather made a reasonableness assumption behind significant opportunities for revenue and margin enhancement. It is unclear when the proxy statement will be filed so that a VVC shareholder vote can be held. After the approval, we would expect an announcement concerning the $2.5B of equity needed to finance the deal. The merger is expected to close in 1Q19.
- Mgmt. noted that the deal was not a response to a fundamental change in the CNP standalone story. Interestingly, they pointed to the Texas market as a reason to pursue the deal. CNP believes that Texas customers are demanding energy services beyond that of what a regulated utility can provide (i.e. individualized requests). CNP believes VVC's energy services company will help provide solutions for these unique customer needs. Separately, they did not sound inclined to sell VVC's infrastructure business; mgmt. likes the consistency of the business which is driven by a backlog of pipeline replacement activity.
- CNP has no plans to fund a portion its VVC acquisition by selling ENBL units. Mgmt. believes the MLP market is not healthy and the company is currently undervalued. That said, CNP is still believes having less exposure to ENBL is the right strategic move for the company overtime.

Consolidated Edison (ED): Not much new, CECONY filing on the horizon

- CECONY is expected to file a rate case in January of 2019, with new rates to be effective in 2020. Recent data points in NY have not been great; ED mentioned that under the state's traditional ROE formula, O&R (in a rate case) would currently receive an ROE of 8.55% despite the recent rise in interest rates. ED plans to address tax reform in next year's filing as well as approval for recovery of $230M of deferred O&M related to the MTA subway power outages. We will be monitoring O&R's rate case to glean any potential implications for when CECONY files.
- Earnings contributions from ED's non-regulated businesses figure to be at the same level for the foreseeable future. ED has a clear line of sight for renewable projects over the next three years ($400M/yr), but mentioned returns are drifting lower. Beyond 2020, renewable projects are proving harder to find as ED does not have a tax appetite. On the midstream side, MVP is on track to be online by year-end; Stagecoach has been quiet and ED sees limited growth opportunities on the horizon.
- NY Transco's segment A and B bids for NYISO's 1,000 MW AC transmission line were ranked in the second and third tier, respectively. ED mentioned that tier three projects have little chance of moving forward. ED's segment A proposal would represent roughly $500M of additional capex. ED's 45% stake in

U21490-AG-CE-0199
Page **1** of **1**

Question:

52. Refer to lines 1-8 on page 16 of Mr. Warriner's direct testimony on new service connections. Please provide a copy of the latest S&P Global (IHS Markit) and Blue Chip Reports report available to the Company that include forecasted interest rates, inflation rates, and housing starts nationally and for Michigan for 2024 and 2025.

Response:

Please see the following pdf file attachments:

1. U21490-AG-CE-0199_Warriner_ATT_1.pdf: S&P Global Market Intelligence US Economic Outlook March 2024 Executive Summary.

2. U21490-AG-CE-0199_Warriner_ATT_2.pdf: S&P Global State Analysis – Michigan 21 Mar 2024.

3. U21490-AG-CE-0199_Warriner_ATT_3.pdf: Wolters Kluwer Blue Chip Economic Indicators/Financial Forecasts Vol. 43, No. 3, March 1, 2024.

Witness: Lincoln D. Warriner
Date: March 26, 2024

Blue Chip Financial Forecasts®

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

Vol. 43, No. 3, March 1, 2024

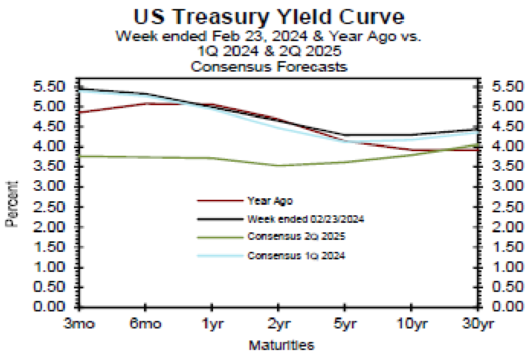
Wolters Kluwer

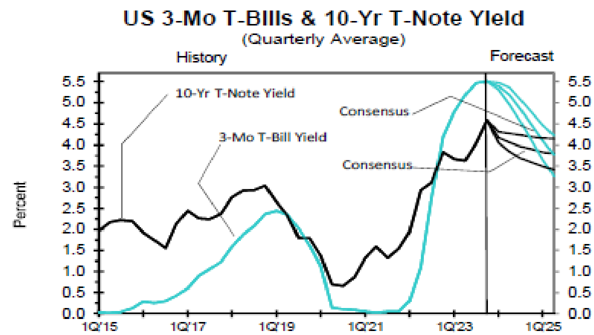
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

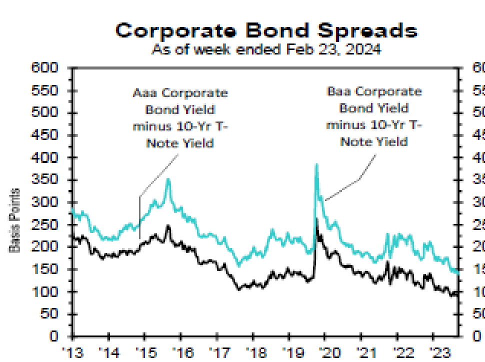
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Qtr	1Q	2Q	3Q	4Q	1Q	2Q
Interest Rates	Feb 23	Feb 16	Feb 9	Feb 2	Jan	Dec	Nov	4Q 2023	2024	2024	2024	2024	2025	2025
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.4	5.2	4.9	4.5	4.2	3.8
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.5	8.4	8.1	7.7	7.3	7.0
SOFR	5.30	5.31	5.31	5.32	5.32	5.33	5.32	5.32	5.3	5.2	4.9	4.5	4.2	3.9
Commercial Paper, 1-mo.	5.32	5.32	5.30	5.32	5.32	5.32	5.33	5.33	5.3	5.2	4.9	4.5	4.1	3.8
Treasury bill, 3-mo.	5.45	5.44	5.43	5.42	5.45	5.44	5.52	5.52	5.4	5.2	4.8	4.5	4.1	3.8
Treasury bill, 6-mo.	5.32	5.30	5.24	5.19	5.21	5.34	5.44	5.45	5.3	5.1	4.8	4.4	4.0	3.7
Treasury bill, 1 yr.	4.99	4.94	4.84	4.76	4.79	4.96	5.28	5.22	4.9	4.8	4.5	4.2	3.9	3.7
Treasury note, 2 yr.	4.65	4.57	4.44	4.30	4.32	4.46	4.88	4.80	4.5	4.3	4.1	3.9	3.7	3.5
Treasury note, 5 yr.	4.29	4.24	4.10	3.93	3.98	4.00	4.49	4.42	4.1	4.0	3.9	3.8	3.7	3.6
Treasury note, 10 yr.	4.30	4.26	4.13	4.01	4.06	4.02	4.50	4.44	4.2	4.1	4.0	3.9	3.8	3.8
Treasury note, 30 yr.	4.44	4.43	4.34	4.23	4.26	4.14	4.66	4.58	4.4	4.3	4.2	4.2	4.1	4.1
Corporate Aaa bond	5.18	5.18	5.08	4.96	5.01	4.95	5.52	5.45	5.0	5.0	4.9	4.8	4.8	4.8
Corporate Baa bond	5.69	5.70	5.59	5.46	5.53	5.51	6.15	6.07	5.9	5.9	5.8	5.8	5.8	5.7
State & Local bonds	4.12	4.13	4.13	4.09	4.09	4.13	4.56	4.52	4.2	4.2	4.2	4.1	4.1	4.0
Home mortgage rate	6.90	6.77	6.64	6.63	6.64	6.82	7.44	7.29	6.8	6.7	6.5	6.3	6.2	6.1

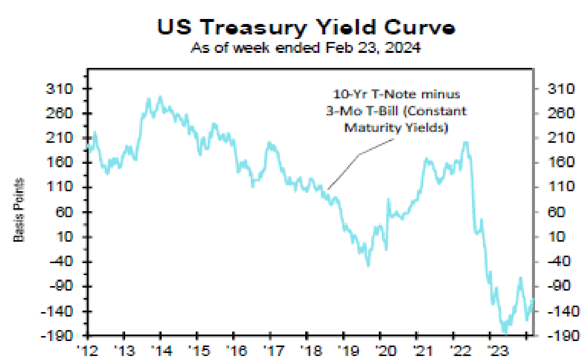
	History								Consensus Forecasts-Quarterly					
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q
Key Assumptions	2022	2022	2022	2022	2023	2023	2023	2023	2024	2024	2024	2024	2025	2025
Fed's AFE $ Index	108.3	113.5	118.8	119.8	115.5	114.6	115.0	116.6	115.5	115.2	114.6	114.0	113.9	113.7
Real GDP	-2.0	-0.6	2.7	2.6	2.2	2.1	4.9	3.2	2.0	1.4	1.3	1.5	1.7	1.9
GDP Price Index	8.5	9.1	4.4	3.9	3.9	1.7	3.3	1.6	2.2	2.3	2.2	2.2	2.1	2.1
Consumer Price Index	9.1	10.0	5.3	4.0	3.8	3.0	3.4	2.7	2.9	2.6	2.4	2.3	2.2	2.2
PCE Price Index	7.7	7.2	4.7	4.1	4.2	2.5	2.6	1.8	2.3	2.2	2.2	2.1	2.1	2.0

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









Question:

65. Refer to pages 48 and 49 of Mr. Warriner's direct testimony on MAOP projects. Please identify what deficiencies or shortcomings exist with each of the pipeline segments listed in Table 17. Explain what specific steps the Company has taken to recreate those missing records by means other than pipeline replacement, as provided in 49 CFR 192.624.

Response:

Response for: Line 1080 Dual Main West of M Avenue City Gate (project 21948 and 21250):

This segment is not 192.624 eligible, as the segment's MAOP is grandfathered and operates below 30% SMYS. The documented MAOP on this line is 325 psi, but currently operates at 400 psi. This project will add capacity to enable the required pressure reduction while avoiding service outages which would likely occur if the pressure on this line was reduced without the additional main.

Response for projects: Line 1002c, Phase 1 Coolidge to 11 Mile & Dequindre (project number TBD); Line 1022 Airport CG to State Rd & State Rd to W Grand River (project 22861 & 22862); Line 1093 Shattuck Rd (project 21676); Line 1006 Groebel Dr to Mound Rd (project 22702):

Records for grandfathering were discovered during Standard Engineering Analysis. Segments have their MAOP established by grandfathering and operate above 30% SMYS in a covered area as defined by 192.624.

Company has investigated the options available in 192.624 and has chosen replacement as the most practicable option to comply.

Response for all other projects:

The Standard Engineering Analysis determined the Pressure Test Documentation for the segments to not be traceable, verifiable, and complete. PHMSA's definition of traceable, verifiable, and complete is provided on page 2 of this response.

Company has investigated options available in 192.624 and has chosen replacement as the most practicable option to comply.

PHMSA's definition of traceable, verifiable, and complete is included in a frequently asked questions document on PHMSA's website. The document website reference is: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-05/Batch-1-FAQs-PHMSA-2019-0225-9-15-20.pdf. The definitions from that document are displayed below:

Traceable *records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, which include mechanical and chemical properties; purchase requisition; or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.*

Verifiable *records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a pipeline segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipeline segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by a qualified individual who observed the test or inspection being performed.*

Complete *records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking such as a corporate stamp or seal. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipeline segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.*

Witness: Lincoln D. Warriner
Date: March 26, 2024

U21490-AG-CE-0213
Page 1 of 1

Question:

66. Refer to Table 17 on page 49 of Mr. Warriner's direct testimony on MAOP projects. Please:

a. Expand the table to include the same actual information for 2023 and forecasted for 9 months ending September 2024, and 12 months ending September 2025 and provide in Excel. Also include any costs beyond 2025 by year to completion of the project.

b. For each of the projects to be undertaken in 2024 or 2025, provide the phases of project development for each project with the related timeline and cost for each phase. Identify the phase of development that the project is currently in.

Response:

Please see the attached Excel document named U21490-AG-CE-0213_Warriner_ATT_1.

Please note that the attached Excel document incorporates an updated estimate for the Line 1080 (project numbers 21948 and 21250). The total project estimate has recently been revised from approximately $75 million to approximately $47 million. Since the company's original application in this proceeding the Line 1080 project has advanced from a conceptual cost estimate to a more informed budgetary estimate. The more informed estimate is updated to reflect the currently planned location of the main construction route. Project designs have been reviewed internally and refined to remove potential costs that were considered in the original estimate included in my testimony and exhibits. The project team also reviewed the current engineering design with construction contractors who were able to provide a lower estimate for construction based on the completed drawings for the Line 1080 project. The cost reductions also reduced the amount of capital work order loadings that are expected to be included in the total capital project cost. This revision will be incorporated into the Company's rebuttal exhibits at the time those are filed in this proceeding.

The information requested is similar to information provided in U21490-SA-CE-161. Please also refer to the information provided in that response.

Witness: Lincoln D. Warriner
Date: March 26, 2024

U21490-AG-CE-0213_Attachment_1.xlsx

Project Number	Project Name	2023 Actuals	2024 Forecast 9 Months ending 9/30/2024	Test Year Forecast ending 9/30/2025	2025 Forecast 3 Months ending 12/31/2025	2026	2027	2028	Current Phase of Development	2025 phase of development	2026 phase of development	2027 phase of development	2028 phase of development
21948 & 21250	Line 1080 Dual Main West of M Avenue City Gate	363	3,415	32,994	10,135	435	-	-	Design	Construction	Closeout		
21788	Line 1009 Huron Park to I-94	-	4,200	600	-	-	-	-	Construction	Closeout			
22511	Line 1022f Vermontville	-	-	209	-	-	-	-	Design	Construction			
22157	Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile	-	203	16,322	-	1,836	-	-	Design	Construction	Closeout		
22150	Line 1002f Macomb ITC Corridor	-	95	1,207	-	145	-	-	Design	Construction	Closeout		
22409	Line 1020 Greenfield Rd	-	-	409	-	45	-	-	Design	Construction	Closeout		
21674 & 21675	Line 1087b E Isabella Rd	-	189	6,290	-	-	-	-	Planning/ Design	Construction			
22494	Line 1009c, 9 Mile to 10 Mile	24	100	270	1,230	12,440	1,560	-	Planning	Planning/ Design	Construction	Closeout	
TBD	Line 1002c, Phase 1 Coolidge to 11 Mile & Dequindre	934	810	902	4,050	16,676	2,420	-	Planning	Planning/ Design	Construction	Closeout	
22861 & 22862	Line 1022 Airport CG to State Rd & State Rd to W Grand River	41	-	714	4,576	25,854	19,073	1,121	Planning	Planning/ Design	Construction	Construction	Closeout
22781	Line 1041 Lapeer Rd	244	250	408	136	3,044	40,784	4,921	Planning	Planning	Design	Construction	Closeout
21676	Line 1093 Shattuck Rd	-	110	1,456	1,240	21,103	2,000	-	Planning	Planning/ Design	Construction	Closeout	
22702	Line 1006 Groebel Dr to Mound Rd	-	-	270	330	4,050	-	-	Planning	Planning/ Design	Construction		
TBD	Line 1026f Mt Hope	-	-	106	679	11,205	-	-	Planning	Planning/ Design	Construction		
TBD	Line 1026i MSU PP	-	-	-	50	714	84	-	Planning	Planning/ Design	Construction		
22532	Line 1090n Davis St	-	-	284	-	-	-	-	Planning/ Design	Construction			

Question:

67. Refer to lines 12-20 on page 50 of Mr. Warriner's direct testimony on MAOP projects. Please identify any MAOP projects in the past 5 years or planned for 2024 and 2025 where the Company was able to re-establish the MAOP and material properties without replacing the pipeline segment. Provide the name of the project, the length, year of the pipeline, the deficiencies in the records, and describe how the Company was able to recreate the records and re-establish the MAOP without pipe replacement.

Response:

There are no historical distribution system MAOP projects that re-established traceable, verifiable, and complete MAOP records without a pipe replacement. Similarly, there are no 2024 or 2025 distribution system projects that will re-establish traceable, verifiable, and complete MAOP records using any method other than pipe replacement.

Witness: Lincoln D. Warriner
Date: March 26, 2024

Question:

68. Refer to the Line 1080 project beginning on pages 51 of Mr. Warriner's direct testimony on MAOP projects. Please:

a. Provide a copy of the Staff's notification.

b. Describe what smart pigging, In Line Inspection (ILI), and other analysis of the pipeline was performed in the past 5 years to establish the integrity of the pipeline and the level of pipe degradation.

c. Provide the pressure level that the pipeline has previously operated at, the current pressure, and the level to which it will be reduced.

d. Explain why this project is included as a MAOP project when the pipeline will be left in place and a new parallel line has been proposed at a cost of more than $70 million.

e. At a cost of more than $10 million per mile, provide the basis showing how the cost was determined, and provide supporting evidence that the forecasted cost is reasonable.

Response:

a. The notification from Staff is provided as an attachment to this response named U21490-AG-CE-0215_Warriner_ATT_1.

b. Responses are as follows:

   1. The affected segment of Line 1080 cannot be pigged with a free-flowing inline inspection tool, therefore smart pigging has not been performed.
   2. The company has performed two direct assessment (or DA) inspections on this segment in the past five years. There were no findings of corrosion beyond expected tolerances.
   3. Digs elsewhere on the system did not have any findings of corrosion beyond expected tolerances.

c. Responses are as follows:

   1. This Line 1080 segment was previously operated at an MAOP 400 PSI.
   2. The current Line 1080 MAOP is 400 PSI.
   3. The MAOP will be reduced to 325 PSI when the Line 1080 project is completed.

d. The Line 1080 Project is included in the MAOP distribution program because the line segment is operated as part of the gas distribution system and currently has grandfathered MAOP documentation consistent with a pressure of 325 PSI, however the line is currently operated at 400 PSI. As a result, the Company will reduce the pressure to the level supported by its grandfathered MAOP documentation, which will be achieved through the installation of an approximately six miles of parallel main.

e. The total project estimate has recently been revised from approximately $75 million to approximately $47 million. Since the company's original application in this proceeding the Line 1080 project has advanced from a conceptual cost estimate to a more informed budgetary estimate. The more informed estimate is updated to reflect the currently planned location of the main construction route. Project designs have been reviewed internally and refined to remove potential costs that were considered in the original estimate included in my testimony and exhibits. The project team also reviewed the current engineering design with construction contractors who were able to provide a lower estimate for construction based on the completed drawings for the Line 1080 project. The cost reductions also reduced the amount of capital work order loadings that are expected to be included in the total capital project cost. This revision will be incorporated into the Company's rebuttal exhibits at the time those are filed in this proceeding. The revised estimate represents an approximate capital cost of $7.07 million per mile.

Witness: Lincoln D. Warriner
Date: March 26, 2024

Question:

252. Refer to the response to AG-CE-0212. Please:

a. Explain why Line 1080 is not eligible under Section 192.624 and how the MAOP is grandfathered.

b. Identify what records were discovered for the other projects that permits grandfathering and what is the result of grandfathering. Identify what section of the rules allow the grandfathering and provide a copy of the rule with specific citation.

Response:

Objection of Counsel: Consumers Energy Company objects to subpart b. of this discovery request to the extent that it seeks legal information that is equally available to the requesting party. The rules of discovery do not obligate Consumers Energy to perform the Attorney General's legal research for her. Subject to this objection and without waiving the objection, the Company responds as follows:

a. Per 49 CFR 192.619(c): for pipelines installed prior to November 12, 1970, the MAOP may be set to the highest actual operating pressure recorded during the 5 years prior to July 1, 1970.

The Line 1080 was installed in the 1950's and 1960's, and the highest actual operating pressure of 325 PSI was observed in 1967, therefore the MAOP is grandfathered at 325 PSI.

192.624 states that grandfathered pipe operating above 30% SMYS is required to be reconfirmed. Line 1080's MAOP is grandfathered as described above, and operates at 22.5% SMYS, therefore the Line 1080 project is not a reconfirmation project because the Company is operating the line below 30% SMYS.

b. Section 192.619(c) addresses how MAOP is grandfathered for pipelines. This section reference is provided below:

Title 49 / Subtitle B / Chapter I / Subchapter D / Part 192 / Subpart L / § 192.619 Previous / Next / Top

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(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instances:

(1) An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611.

MAOP grandfathering is applicable for the following projects in addition to the Line 1080 project:

- **Line 1002c**
    - Line 1002c was installed in 1959/1960, and the highest actual operating pressure of 300 PSI was observed on 11/10/1966, therefore the MAOP is grandfathered.
    - Line 1002c's MAOP is grandfathered and operates at 36.6% SMYS, therefore the Line 1002c project described on page 56 of my direct testimony, lines 11 through 23 requires MAOP reconfirmation.
- **Line 1006**
    - Line 1006 was installed in 1959, and the highest actual operating pressure of 300 PSI was observed on 11/10/1966, therefore the MAOP is grandfathered.
    - Line 1006's MAOP is grandfathered and operates at 36.6% SMYS, therefore the Line 1006 project described on page 58, lines 11 through 20 requires MAOP reconfirmation.
- **Line 1022**
    - Line 1022 was installed in 1963, and the highest actual operating pressure of 400 PSI was observed on 11/25/1969, therefore the MAOP is grandfathered.
    - Line 1022's MAOP is grandfathered and operates at 36.57% SMYS, therefore the Line 1022 project described on page 57, lines 1 through 13 requires reconfirmation.
- **Line 1093**
    - Line 1093 was installed in 1967, and the highest actual operating pressure of 330 PSI was observed on 8/28/1968, therefore the MAOP is grandfathered.
    - Line 1093's MAOP is grandfathered and operates at 30.2% SMYS, therefore the Line 1093 project described on page 58 lines 1 through 10 requires reconfirmation.

Witness: Lincoln D. Warriner
Date: April 15, 2024

U21490-SA-CE-162
Requested By: Cindy L. Creisher (CLC-33 - 1)
Respondent: Lincoln D. Warriner
Date of Response: 3/5/2024
Page **1** of **1**

Question:

With reference to the direct testimony of Witness Lincoln Warriner on pages 62-63, provide the actual investment amounts for 2023 and the test year ending September 30, 2025 for the Cathodic Protection Distribution sub-program (reference page 62, lines 8-12), RMU installations (reference page 62, lines 18-22), rectifier and groundbed installations and replacements (reference page 63, lines 8-12), and other capital repairs (reference page 63, lines 18-22). Additionally, provide the number of projects completed or projected for RMU installations, rectifier and groundbed, and other repairs by year (2018 through 2025 and test year).

Response:

Actual investment amounts for the Cathodic Protection Distribution sub-program are included in my response to U21490-SA-CE-163. Please see that response for detail on the 2023 preliminary historical investment amounts.

The Company does not have a specific test year ending September 30, 2025 projection for RMU installations, rectifier and groundbed installations and replacement, and other capital repairs. That projection was calculated at a total sub-program level as described on page 64, lines 4 through 7.

The number of projects completed or projected for RMU installations, rectifier and groundbed installations/replacements and other capital repairs by year are displayed below. The Company made the following calculation assumptions for 2024 and 2025:

1) RMU's are excluded from 2024 and 2025 projections.
2) Rectifier/Groundbed and Other capital repairs will be similar to the 2022 actual historical volume, but will cost 20% more in 2024 than in 2022 and 25% more in 2025 than in 2022. In my testimony (pages 64 and 65), I explain that the increases in 2024 and 2025 are due primarily to increasing material and contractor costs.

Number of Projects Completed/Projected

	Number of Projects Completed						Projected Projects	
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
RMU Installations	95	98	103	105	98	3	0	0
Rectifier and Groundbed installations and replacements	42	45	33	39	82	61	82	82
Other capital repairs	1711	1074	1246	764	971	1239	971	971

Notes: RMU Installations are defined as the number of RMU units purchased.
Rectifier, Groundbed installations/replacements and Other capital repairs are defined as field completed work orders.

U21490-SA-CE-163
Requested By: Cindy L. Creisher (CLC-34 - 1)
Respondent: Lincoln D. Warriner
Date of Response: 2/29/2024
Page **1** of **1**

Question:

With reference to the direct testimony of Witness Lincoln Warriner on pages 64-65 regarding the Cathodic Protection Distribution sub-program, provide further detail to quantify the increasing material and contractor costs that driving the increased in projected expenditures for the program.

Response:

Please see the table below for detailed quantification of the increasing material and contractor costs in the Cathodic Protection Distribution sub-program experienced by the Company in 2022 and 2023. Projected capital expenditures for 2024 are approximately 23% below the 2023 preliminary actual amount, and projected capital expenditures for 2025 are approximately 20% below the 2023 preliminary actual amount.

	Cost Element					
	Labor	Capitalized Engineering /Supv	Material	Contractor	Non-Labor Overheads	Non-Labor Other
Cathodic Protection Distribution sub-program						
• 2018 historical actual: $5,961,948;	1,134,903	1,349,790	838,064	1,485,564	209,839	943,788
• 2019 historical actual: $5,039,720;	851,295	1,222,691	905,919	996,438	126,775	936,601
• 2020 historical actual: $6,663,545;	1,411,639	1,508,191	1,078,381	1,096,742	239,280	1,329,312
• 2021 historical actual: $6,976,687; and	1,322,679	1,573,724	1,050,280	1,383,444	266,922	1,379,639
• 2022 historical actual: $8,582,806.	1,429,620	1,853,355	2,024,101	1,558,244	309,676	1,407,810
• 2023 preliminary historical actual: $12,391,559	1,897,353	3,069,524	2,751,703	2,063,836	404,048	2,205,096
RMU Installations						
• 2018 historical actual: $113,036;	6,369	28,391	0	57,376	0	20,900
• 2019 historical actual: $608,746;	63,495	167,562	252,787	42,332	1,097	81,472
• 2020 historical actual: $532,356;	77,454	93,509	294,355	31,945	6	35,088
• 2021 historical actual: $720,208; and	77,673	165,806	304,047	71,141	0	101,541
• 2022 historical actual: $632,899.	84,206	153,220	301,582	3,280	0	90,611
• 2023 preliminary historical actual: $0	0	0	0	0	0	0
Rectifier and Groundbed installations and replacements						
• 2018 historical actual: $1,171,721;	162,777	271,959	213,757	280,641	26,993	215,594
• 2019 historical actual: $1,191,788;	162,097	288,471	216,952	301,172	20,093	203,003
• 2020 historical actual: $1,001,186;	160,316	229,542	191,293	194,818	22,413	202,804
• 2021 historical actual: $1,185,666; and	201,509	262,718	237,110	216,365	38,343	229,621
• 2022 historical actual: $2,220,388.	299,135	484,051	507,301	505,165	58,417	366,319
• 2023 preliminary historical actual: $2,429,288	317,323	602,862	486,611	505,362	61,841	455,289
other capital repairs						
• 2018 historical actual: $4,677,192;	965,757	1,049,440	624,307	1,147,547	182,846	707,294
• 2019 historical actual: $3,239,186;	625,704	766,658	436,180	652,933	105,586	652,126
• 2020 historical actual: $5,130,002;	1,173,869	1,185,141	592,733	869,979	216,860	1,091,420
• 2021 historical actual: $5,070,813; and	1,043,496	1,145,200	509,123	1,095,937	228,579	1,048,478
• 2022 historical actual: $5,729,519.	1,046,279	1,216,084	1,215,217	1,049,800	251,259	950,880
• 2023 preliminary historical actual: $9,962,271	1,580,030	2,466,662	2,265,092	1,558,474	342,207	1,749,807

U21490-AG-CE-0217
Page **1** of **1**

Question:

70. Refer to pages 62-63 of Mr. Warriner's direct testimony on the Cathodic Protection sub-program. For each of the bulleted sub-categories, please provide the actual 2023 costs and the number of projects or units completed each year 2018 to 2023.

Response:

Please refer to responses provided to U21490-SA-CE-162 and U21490-SA-CE-163. The requested details are included in those responses.

Witness: Lincoln D. Warriner
Date: March 26, 2024

Question:

71. Refer to lines 18-22 on page 64 of Mr. Warriner's direct testimony on the Cathodic Protection sub-program. Please provide the basis determining the $8,629,402 forecasted amount for 2024 and explain why it will increase by more than 50% from 2022.

Response:

Lines 18-22 on page 64 of my direct testimony state the following:

> The calendar year 2024 forecast for the Cathodic Protection Distribution sub-program is $9,562,625. This forecast includes $0 for RMU installations, $933,223 for Rectifier and Groundbed installations and replacements, and $8,629,402 for other capital repairs. The 2024 calendar year forecast is 11.4% more than the 2022 historical actual investment, and approximately 43.9% higher than the 2018 to 2022 historical average.

This question asks specifically for detail on the $8,629,402 for other capital repairs, which represents all Cathodic Protection Distribution work orders excluding those work orders associated with RMU installations and Rectifier and Groundbed installations and replacements. The 2024 projection was developed for all Cathodic Protection Distribution work orders using calculation assumptions identified in my response to U21490-SA-CE-162. The $8,629,402 for other capital repairs is the result of reducing the total Cathodic Protection Distribution projection by the amounts projected for RMU Installations and Rectifier and Groundbed Installations. The reason for the increase over the 2022 historical actual amount is that increasing costs were observed during 2023. For reference, the 2022 historical actual, 2023 preliminary actual, and 2024 projection for the three activities within Cathodic Protection Distribution are provided in the table below:

	2022 Historical Actual	2023 Preliminary Actual	2024 Projection
RMU Installations	632,899	0	0
Rectifier and Groundbed installations/replacements	2,220,388	2,429,288	933,233
Other Capital Repairs	5,729,519	9,962,271	8,629,402
Total Cathodic Protection Distribution	**8,582,806**	**12,391,559**	**9,562,635**

Witness: Lincoln D. Warriner
Date: March 26, 2024

U21490-SA-CE-164
Requested By: Cindy L. Creisher (CLC-35 - 1)
Respondent: Lincoln D. Warriner
Date of Response: 3/5/2024
Page **1** of **1**

Question:

With reference to the direct testimony of Witness Lincoln Warriner on pages 68-69 regarding the projected expenditures for the Augment program, provide a list of completed or planned projects for 2023, 2024, and 2025 with the capital expenditure amount by year, including the test year (consistent with the data provided in Table 19 on page 67 for investments from 2018 through 2022). If the sum of the projects identified for 2024 and 2025 (or 9 months ending September 30, 2024, and test year ending September 30, 2025) do not total the Augment program expenditures as provided in Exhibit A-119 (LDW-5), provide detail as to how the Company arrived at total projected expenditure level for each year.

Response:

The requested table with updates for 2023 preliminary actual, and planned projects for 2024 and 2025 are provided below. The test year projection of $5.562 million was calculated in total for the Augment program using monthly estimates of capital expenditures provided in WP-LDW-1. The Company typically identifies additional "other projects" after the conclusion of each winter heating season. The 2023 preliminary actual amount exceeds the 2023 projection in this case by approximately $1.1 million.

Table 17: Historical Actual Augment Investments by Year and Projections for 2024 and 2025

	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Preliminary Actual	2024 Projected	2025 Projected
Caledonia HP Phase 1	$566,791	$13,613	$488					
Caledonia HP Phase 2	$172,330	$10,319			($512)			
Caledonia HP Phase 3	$19,323,678	$1,724,630	$35,961	($153)				
Gratiot Ave HP Repl				$2,803,277	$1,514,207			
Caledonia MP / Cherry Valley Ave			$1,778,302	$287,842	($100)			
Hickory Corners				$910,795	$455,855			
Shaffer Rd East of Alamando					$4,052,568	$18,338		
Imlay City Rd & Lk Pleasant					$1,626,475			
W Sanilac Rd					$1,032,909			
Climax CG 8 Inch HP						$1,925,844		
Walled Lake - Welch and Oak						$1,723,201		
W Summit Dr						$410,598		
Crooked Lake Rd - Latson Rd							$303,353	
Celery & River St Galesburg							$2,391,637	
Freeman and Dale Rd/Midland							$2,500,000	
Orion City Gate							$1,000,000	
Harry St and Harvard 450 ft 2 in MP							$65,000	
Elk Lake Rd and Imlay City Rd 15 ft 2 in MP							$29,976	
Beaverton 12 in HP Shaffer Rd E of Alamando PT2								$3,670,511
Burton Dr and Belsay Pear Dr 1100 ft 6 in and 2 in								$672,003
Rives Junction Road/Parnall Rd								$356,068
Other Projects	($569,187)	$1,811,393	$1,784,195	$2,501,265	$1,514,431	$367,947	$463,035	$312,511
Total Augment	**$19,493,612**	**$3,559,955**	**$3,598,945**	**$6,503,025**	**$10,195,833**	**$4,445,928**	**$6,753,001**	**$5,011,093**

Question:

72. Refer to Table 19 on page 67 of Mr. Warriner's direct testimony on Demand Augment projects. Please:

a. Expand the table to include the projects for the following periods and the cost for 2023 and forecasted for 2024, 2025, 9 months ending September 2024, and 12 months ending September 2025 and provide in Excel. Also include any costs past 2025 by year to completion of the project.

b. For each of the projects to be undertaken in 2024 or 2025, provide the phases of project development for each project with the related timeline and cost for each phase. Identify the phase of development that the project is currently in.

Response:

a. Please refer to my response to U21490-SA-CE-164. An Excel version of the table provided in that response is included as U21490-AG-CE-0219-Warriner_ATT_1.xlsx.

b. Phases of project development and associated timelines for each project are as follows:

   a. Crooked Lake Rd - Latson Rd: (current phase: Field Complete)
      i. Survey required 8/21/2023
      ii. Design not started 9/25/2023
      iii. Design 90% complete 9/13/2023
      iv. Designed 10/9/2023
      v. Released for construction 1/9/2024
      vi. Construction Start: 1/22/2024
   b. Celery & River St Galesburg: (current phase: Designed)
      i. Survey required 11/13/2023
      ii. Design not started 12/18/2023
      iii. Design 90% complete N/A
      iv. Designed 1/12/2024
      v. Released for construction 3/18/2024
      vi. Construction Start: 4/15/2023.
   c. Freeman and Dale Rd/Midland: (current phase: Canceled)
      i. Survey required N/A
      ii. Design started N/A
      iii. Design 90% complete N/A
      iv. Designed N/A
      v. Released for construction N/A
   d. Orion City Gate medium pressure main: (current phase: Designed)
      i. Survey required 11/14/2023
      ii. Design not started 1/31/2024
      iii. Design 90% complete 2/28/2024

  iv. Designed 2/28/2024
  v. Released for construction 5/1/2024
  vi. Construction Start 5/29/2024

e. Harry St and Harvard 450 ft 2 in MP: (current phase: Design in Progress)
  i. Survey required 3/4/2024
  ii. Design 90% complete N/A
  iii. Designed 5/06/2024
  iv. Released for construction 7/08/2024
  v. Construction Start 8/5/2024

f. Elk Lake Rd and Imlay City Rd 15 ft 2 in MP: (current phase: Designed)
  i. Survey required 4/1/2024
  ii. Design 90% complete 12/12/2023
  iii. Designed 7/17/2023
  iv. Released for construction 8/05/2024

g. Beaverton 12 in HP Shaffer Rd E of Alamando PT2: (current phase: Survey required)
  i. Survey required TBD
  ii. Design not started TBD
  iii. Design started TBD
  iv. Design 90% complete TBD
  v. Designed TBD
  vi. Released for construction TBD

h. Burton Dr and Belsay Pear Dr 1100 ft 6 in and 2 in: (current phase: Designed)
  i. Survey required 4/21/2023
  ii. Designed 1/4/2024
  iii. Released for construction 7/08/2024
  iv. Construction Start 8/5/2024

i. Rives Junction Road/Parnall Rd: (current phase: Survey required)
  i. Survey required TBD
  ii. Design not started TBD
  iii. Design started TBD
  iv. Design 90% complete TBD
  v. Designed TBD
  vi. Released for construction TBD

Witness: Lincoln D. Warriner
Date: March 26, 2024

U21490-AG-CE-0219_Attachment_1.xlsx

Table 17: Historical Actual Augment Investments by Year and Projections for 2024 and 2025

	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Preliminary Actual	2024 Projected	2025 Projected
Caledonia HP Phase 1	$566,791	$13,613	$488					
Caledonia HP Phase 2	$172,330	$10,319			($512)			
Caledonia HP Phase 3	$19,323,678	$1,724,630	$35,961	($153)				
Gratiot Ave HP Repl				$2,803,277	$1,514,207			
Caledonia MP / Cherry Valley Ave			$1,778,302	$287,842	($100)			
Hickory Corners				$910,795	$455,855			
Shaffer Rd East of Alamando					$4,052,568	$18,338		
Imlay City Rd & Lk Pleasant					$1,626,475			
W Sanilac Rd					$1,032,909			
Climax CG 8 Inch HP						$1,925,844		
Walled Lake - Welch and Oak						$1,723,201		
W Summit Dr						$410,598		
Crooked Lake Rd - Latson Rd							$303,353	
Celery & River St Galesburg							$2,391,637	
Freeman and Dale Rd/Midland							$2,500,000	
Orion City Gate							$1,000,000	
Harry St and Harvard 450 ft 2 in MP							$65,000	
Elk Lake Rd and Imlay City Rd 15 ft 2 in MP							$29,976	
Beaverton 12 in HP Shaffer Rd E of Alamando PT2								$3,670,511
Burton Dr and Belsay Pear Dr 1100 ft 6 in and 2 in								$672,003
Rives Junction Road/Parnall Rd								$356,068
Other Projects	($569,187)	$1,811,393	$1,784,195	$2.501,265	$1,514,431	$367,947	$463,035	$312,511
Total Augment	**$19,493,612**	**$3,559,955**	**$3,598,945**	**$6,503,025**	**$10,195,833**	**$4,445,928**	**$6,753,001**	**$5,011,093**

Question:

197. Refer to page 35 and Table 1 of Ms. Pascarello's direct testimony on the EIRP. Please:

a. Expand this table to show the annual miles of main and services retired and replaced from 2012 to 2023 and forecasted for 2024, 2025 and the projected test year with revised cumulative numbers retires and remaining miles and services. Provide this information in Excel.

b. Explain which lines are included in the Total line at the top of the table and verify that the total number is correct for each year.

c. Explain why the Additional Pipe Replacements on the last two lines of the table are included in the table.

Response:

a. Please see attachment U21490-AG-CE-0356_Pascarello_ATT_1. The number of services is not included in this attachment as EIRP only reports total services and not by material type. The total number of services by year is included in attachment U21490-AG-CE-0358_Pascarello_ATT_1.

b. The purpose of Table 1 is to provide information on the retired miles of vintage materials included in the scope of EIRP. The Total line of Table 1 represents EIRP classified vintage materials retired as defined in my direct testimony on page 33, lines 1 through 11. The numbers represented in the TOTAL line are representing vintage miles replaced.

c. Also included in Table 1 but **not** included in the TOTAL line are additional miles retired of non-qualifying (non-vintage) materials (coated & wrapped, and plastic) retired as part of EIRP projects.

Witness: Kristine A. Pascarello
Date: April 8, 2024

U21490-AG-CE-0356_Pascarello_ATT_1

MILES OF EIRP CLASSIFIED MAIN PIPE REPLACED BY YEAR

PIPE TYPE:	Miles of Pipe by Pipe Type in EIRP Program Scope	EIRP 2012 Actuals[1]	EIRP 2013 Actuals[1]	EIRP 2014 Actuals[1]	EIRP 2015 Actuals[1]	EIRP 2016 Actuals[1]	EIRP 2017 Actuals[1]	EIRP 2018 Actuals[1]	EIRP 2019 Actuals[1]	EIRP 2020 Actuals[1]	EIRP 2021 Actuals[1]	EIRP 2022 Actuals[1]	EIRP 2023 Preliminary[1]	Cumulative EIRP Retired as of 12/31/23[1]	Estimated Cumulative Retired by Other Programs as of 12/31/23	Est. Miles Remaining as of 12/31/23	EIRP 2024 Forecasted[1]	EIRP 2025 Forecasted[1]	**Test Year Total**
TOTAL:	2869.2	28.4	62.0	56.3	78.3	70.1	63.4	43.4	35.3	62.5	119.1	84.3	91.1	794.1	401.0	1,674.1	104.8	105.7	**105.5**
Cast Iron	580	5.3	29.9	28.7	32.9	23.1	24.0	13.3	9.3	13.9	50.6	23.0	32.7	286.7	101.8	191.5	41.5	31.4	**34.0**
Bare Steel	1033.4	5.0	16.9	12.9	24.8	25.8	21.7	14.0	14.0	26.6	46.4	56.1	22.0	286.3	129.8	617.3	39.8	25.3	**28.9**
Threaded & Coupled	1061.7	1.0	6.0	10.3	11.0	17.1	14.2	11.2	9.6	19.8	14.9	4.2	29.7	148.8	163.0	749.9	17.7	30.1	**27.0**
Wrought Iron	21.6	0.0	0.2	0.8	2.7	0.3	0.8	0.0	0.0	0.0	0.4	0.0	0.2	5.3	5.8	10.5	0.2	0.0	**0.1**
X-trube	0.9	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	**0.0**
Copper	1.6	0.0	0.2	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.5	0.0	0.0	0.0	**0.0**
Coated & Wrapped on Standard Pressure[3]	108.35	(7.8)	(6.8)	(5.8)	(4.8)	(3.8)	(2.8)	(1.8)	(0.8)	0.2	1.2	2.2	3.2	(27.6)					
TOD	100	0.0	0.0	0.0	4.4	1.0	0.0	3.6	1.6	2.3	6.7	1.1	6.5	27.1			5.6	18.9	**15.5**
LFERW	70	17.0	8.0	3.6	2.5	2.5	2.6	1.4	0.8	0.0	0.0	0.0	0.0	38.4			0.0	0.0	**0.0**
Additional Pipe Replacement:																			
Plastic[2]		0.2	1.4	0.9	1.8	0.6	1.5	1.2	0.8	1.7	3.2	6.6	9.8	29.7			3.5	2.2	**2.5**
Coated & Wrapped[2]		1.1	10.7	11.3	10.8	12.9	13.3	6.3	9.7	7.4	12.4	39.5	25.2	160.6			20.4	15.0	**16.4**

Notes:

1) Does not include miles of EIRP pipe type that were replaced as part of other programs like Civic Improvement or Emergent CE Initiated.

2) It is necessary to replace some coated and wrapped steel and plastic pipe as part of EIRP projects due to the configuration of the system, project constructability code 3 condition, but coated and wrapped and plastic are not EIRP targeted pipe type.

3) As part of the NGDP, Coated & Wrapped steel pipe on standard pressure does qualify under ERIP while Coated & Wrapped steel pipe on medium pressure does not qualify under EIRP.

4) Information for 2023 is preliminary actual data subject to close-out; Final 2023 actual data will be provided in the 2023 EIRP Performance Report to be filed by 4/30/24

U21490-AG-CE-0357
Page **1** of **1**

Question:

198. Refer to page 35 of Ms. Pascarello's direct testimony on the number of miles of main installed under the EIRP. Please provide the following information in Excel:

a. A comparison of the number of miles of retired mains to the miles of mains installed by year overall and, if possible, by pipe type from 2012 to 2023 actual and forecasted for 2024, 2024, first 9 months 2024, and for the 12 months ending September 2025.

b. The cost of installed mains and services for each year 2012 to 2023 actual and forecasted for 2024, 2024, first 9 months 2024, and for the 12 months ending September 2025.

Response:

Please see attachment U21490-AG-CE-0357_Pascarello_ATT_1.

Witness: Kristine A. Pascarello
Date: April 8, 2024

U21490-AG-CE-0357_Pascarello_ATT_1																	
Amounts calculated by AG																	
																9 mo ending	12 mo ending
	Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	9/30/2024	9/30/2025
Grid/ Seg	Retired (All Pipe Types)	11.83	60.75	55.03	82.44	79.48	75.70	45.88	43.45	67.26	127.89	129.28	119.67	123.64	104.08	92.73	108.97
													898.67				
Grid/ Seg	Installed (Grid/ Segment)	10.63	56.79	51.55	80.27	79.50	76.67	47.42	48.52	67.07	150.38	161.08	105.43	106.53	91.62	79.90	95.34
													935.30				
Grid/ Seg	Construction (Grid/ Segment)	$ 5,358,267	$ 26,808,020	$ 34,547,074	$ 71,085,748	$ 66,821,945	$ 75,331,465	$ 56,780,687	$ 62,138,870	$ 93,204,040	$ 199,496,064	$ 226,017,787	$ 166,630,015	$ 171,859,271	$ 157,125,954	$ 123,755,518	$160,346,864
													$ 1,084,219,981				
													1,159,223.87				
TOD/ HP Steel	Retired (All Pipe Types)	0.86	5.23	9.82	6.01	1.62	0.00	3.58	1.57	4.40	6.71	1.06	6.49	5.60	18.86	4.03	15.55
													47.34				
TOD/ HP Steel	Installed (TOD/ HP Steel)	1.00	6.67	9.71	4.31	1.47	0.00	5.44	2.23	4.17	6.84	1.03	6.82	8.66	20.82	6.24	17.78
													49.68				
TOD/ HP Steel	Construction (TOD/ HP Steel)	$ 1,982,162	$ 6,319,393	$ 20,261,847	$ 9,081,440	$ 9,639,629	$ -	$ 27,829,328	$ 11,312,164	$ 20,845,608	$ 26,599,909	$ 2,333,677	$ 10,196,616	$ 42,176,742	$ 79,040,000	$ 30,371,388	$ 69,637,839
													$ 146,401,774				
Program	Carry-Over	$ -	$ 419,062	$ 1,533,183	$ 1,983,437	$ 3,069,843	$ 2,893,137	$ 2,178,946	$ 4,929,884	$ 4,497,213	$ 1,982,116	$ 17,292,156	$ 5,100,000	$ 5,300,000	$ 5,400,000	$ 3,816,519	$ 5,359,742
Program	Future	$ 554,574	$ 4,458	$ 100,901	$ 25,620	$ -	$ 2,870,034	$ -	$ -	$ -	$ 2,675,717	$ 2,505,827	$ -	$ -	$ -	$ -	$ -
Program	Survey/Engineering	$ -	$ 1,517,224	$ 767,310	$ 366,816	$ 109,806	$ 805,167	$ 1,275,102	$ 779,262	$ 4,305,676	$ 6,195,865	$ -	$ -	$ -	$ -	$ -	$ -
Program	Fleet	$ 5,917,889	$ 12,852,254	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program	Tools	$ 849,510	$ 2,109,120	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program	**Total Cost**	**$ 14,662,402**	**$ 50,029,531**	**$ 57,210,315**	**$ 82,543,062**	**$ 79,641,223**	**$ 81,899,803**	**$ 88,064,063**	**$ 79,160,180**	**$ 122,852,536**	**$ 236,949,671**	**$ 248,149,447**	**$ 181,926,631**	**$ 219,336,013**	**$ 241,565,954**	**$ 157,943,425**	**$235,344,444**
Cost per Mile																	
	Grid/Seg	$ 504,290	$ 472,092	$ 670,216	$ 885,547	$ 840,560	$ 982,587	$ 1,197,312	$ 1,280,669	$ 1,389,699	$ 1,326,630	$ 1,403,103	$ 1,580,480	$ 1,613,250	$ 1,715,065	$ 1,548,930	$ 1,681,775
	Rolling 3 -year average			$ 548,866	$ 675,951	$ 798,774	$ 902,898	$ 1,006,819	$ 1,153,522	$ 1,289,226	$ 1,332,333	$ 1,373,144	$ 1,436,738	$ 1,532,277	$ 1,636,265		
	TOD/HP Steel	$ 1,990,456	$ 947,909	$ 2,087,505	$ 2,107,415	$ 6,562,306		$ 5,118,929	$ 5,064,719	$ 4,995,453	$ 3,889,866	$ 2,271,721	$ 1,495,130	$ 4,870,294	$ 3,796,350	$ 4,870,956	$ 3,916,639
	Rolling 3 -year average			$ 1,675,290	$ 1,714,276	$ 3,585,742				$ 5,059,700	$ 4,650,013	$ 3,719,013	$ 2,552,239	$ 2,879,048	$ 3,387,258		

Question:

202. Refer to lines 10-30 on page 42 of Ms. Pascarello's reductions to the EIRP cost per mile. Please provide the cost per mile reduction achieved in 2023 from 2022.

Response:

My direct testimony does not state that there was a cost per mile reduction in 2023 compared with 2022, but rather states that "the Company has implemented changes expected to maintain and potentially decrease the cost-per-mile for EIRP projects." There is not a cost-per-mile reduction comparing 2022 to 2023. However, in implementing the changes described on page 42 of my direct testimony, the cost-per-mile for plastic pipe was reduced from the projected amount of $1,680,794 in 2023 to an actual preliminary 2023 cost-per-mile amount of $1,580,480. See page 43, line 4 of my direct testimony, compared with attachment U21490-SA-CE-108_Pascarello_ATT_1, line 38. The Company was able to achieve this reduction of over $100,000 per mile even while completing the increased standard pressure conversion work in 2023 (described on page 43 of my direct testimony), which requires additional hours and project expenditures with no associated installed miles, increasing the average cost per mile.

Witness: Kristine A. Pascarello
Date: April 9, 2024

Question:

203. Refer to page 42 of Ms. Pascarello's direct testimony on the EIRP cost per mile. Please:

a. Provide the actual cost per mile for 2023.

b. Explain what the standard pressure conversion entails, why it was necessary, and at which installations.

c. Provide the additional cost for the standard pressure conversions in 2023 and in prior years and how many such conversion were done each year and per mile.

d. Provide the number of standard pressure conversions planned for 2024, 2025, first 9 months of 2024, and for the 12 months ending September 2025 with the related incremental cost in Excel.

Response:

<u>Objection of Counsel</u>: Consumers Energy Company objects to this discovery request because it seeks the results of an analysis that the Company has not performed. Without waiving this objection, Consumers Energy responds as follows:

a. The preliminary actual cost per mile for plastic in 2023 is $1,580,480.

b. A standard pressure conversion is one way the Company reduces cost during a standard pressure (SP) replacement project. When the SP system in an area is being replaced, and there is existing plastic main and services within that project boundary, the Company will determine if the existing plastic main can remain in place and be converted to medium pressure (MP), rather than having to replace the existing plastic with new plastic. Converting existing plastic pipe that is still within its usable life cycle is less expensive than replacing the piping with new plastic piping, reducing costs while still eliminating the SP system in the project area.

   The main is broken down in to sections small enough to convert in an appropriate timeframe, which is usually one day, since all customers attached to that section will be interrupted during the conversion process. The conversion process goes as follows:

   - A leak survey is performed for all the main and services to be converted before conversion work begins.
   - Each above-grade portion of the service and each meter location is visually inspected to verify they meet current standards.
   - The services in the section are turned off and the main is isolated from the SP feed.
   - The main pressure is brought up to Medium Pressure by tying it in to a MP feed.
   - All meter stands are replaced, and a top-connect bypass meter stand is installed along with the proper meter and regulation for the new pressure.

- A leak survey is performed when the conversion is complete to ensure moving to a higher pressure has not created any leaks on this existing (now converted) system.

The Company plans to eliminate the SP system as part of the NGDP. More information regarding the standard pressure system is described in the NGDP (Exhibit A-43 (NPD-1)) on pages 67 and 68.

c. The requested data is not available. The Company does not track the costs or the number of standard pressure conversions separately. The number of standard pressure conversions provided on page 43 of my direct testimony are based on recently completed work. There is no historical tracking of this activity.

d. The Company does not project the costs of standard pressure conversions separately. The costs are included in the projected cost per mile described on page 43, lines 19 through 21 of my direct testimony. In addition, the Company does not agree with the characterization of these SP conversions as representing "incremental cost." While SP conversions will increase the cost-per-mile because they include work that does not involve installing miles of pipe, SP conversions reduce total costs because they avoid installment of all new plastic piping while still eliminating the SP system in the project area. Reviewing the 2024 projects, the Company is projecting standard pressure conversions in ten phases within the EIRP projects. Six of those ten phases are projected to be completed within the 9 months ending September 30, 2024. The Company is projecting standard pressure conversions in seven phases within the 2025 EIRP projects, though the engineering design work for 2025 is still in progress. The number of phases with standard pressure conversions to be completed by 12 months ending September 2025 is still to be determined.

Witness: Kristine A. Pascarello
Date: April 9, 2024

Question:

206. Refer to page 51 of Ms. Pascarello's direct testimony on replacement of Line 1010. Please:

a. Explain why this MAOP project is being done under the non-modeled material condition program and not with other MAOP transmission projects.

b. Identify what deficiencies or shortcomings exist with traceable and verifiable records with this pipeline.

c. Describe what smart pigging, In Line Inspection (ILI), and other analysis of the pipeline was performed in the past 5 years to establish the integrity of the pipeline and the level of pipe degradation.

d. Provide a copy of the analysis showing the evaluation performed by the Company to re-establish the MAOP by hydrotesting various segments of the targeted pipeline or by other means before reaching the conclusion of replacement of the pipelines.

e. Provide the cost for the replacement project for the first 9 months of 2024 and 12 months ending September 2025.

Response:

a. This project was started in 2021, prior to the establishment of the other MAOP projects.
b. Line 1010 was purchased from another utility and pressure test records are missing.
c. The Company performed three direct assessment digs in 2020.
d. The Company explored the option to re-establish the MAOP by hydrotesting the line. This option was not selected because upon investigation, it was determined that it was not feasible to retest all of Line 1010 while serving the customers on the system. There is a level of impracticality and risk for re-testing a distribution line of this length, especially when it comes to the customer meter stands. To test a segment, it is necessary to isolate each meter, and for high pressure ("HP") customers, each HP regulator stand. These customers would be off for the duration of the test prep, the actual test, and the reinstatement of that section of pipe. Additionally, the testing would have to be performed in rolling segments, which would require additional work to be able to isolate individual test segments.
e. The projected cost for the 9 months ending September 2024 is $5,499,385. The projected cost for the 12 months ending September 2025 is $9,850,000.

Witness: Kristine A. Pascarello
Date: April 9, 2024

Question:

209. Refer to Table 6 on page 64 of Ms. Pascarello's direct testimony on vintage services replacement. Please expand the table to includes actual 2023 and the first nine months forecast for 2024, and provide it in Excel.

Response:

Please see attachment U21490-AG-CE-0368_Pascarello_ATT_1.

Witness: Kristine A. Pascarello
Date: April 8, 2024

U21490-AG-CE-0368_Pascarello_ATT_1

Table 6: Vintage Services Replacements

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Projected 2023	Preliminary Actual 2023	Projected 2024	Projected 12 Mos Ending 9/30/2024	Projected 2025	Projected 12 Mos Ending 9/30/2025
VSR Program Units	6,307	9,381	5,571	5,456	5,056	2,176	1,519	1,228	2,424	1,859	4,164	3,729
VSR Unit Cost	$ 5,322	$ 6,037	$ 7,260	$ 7,848	$ 6,518	$ 7,888	$ 8,151	$ 9,246	$ 7,496		$ 7,501	$ 7,642
VSR Program Spend ($000)	$ 33,564	$ 56,634	$ 40,443	$ 42,818	$ 32,955	$ 17,165	$ 12,381	$ 11,354	$ 18,171	$ 14,363	$ 31,233	$ 28,496
EIRP/Other Programs	5,169	4,042	4,064	4,291	5,245	8,235	2,741	3,576	2,758	1,843	2,744	2,748
Total Services Replaced	11,476	13,423	9,635	9,747	10,301	10,411	4,260	4,804	5,182	3,702	6,908	6,477
Total Services Remaining	170,478	157,055	147,420	137,673	127,372	116,961	112,701	112,157	107,519		100,611	102,338

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Question:

211. Refer to lines 8-16 on page 67 and lines 1-10 on page 68 of Ms. Pascarello's direct testimony on the AMD. Please:

a. State whether the Company had problems identifying true gradable gas leaks prior to the use of the AMD system. If yes, please identify those failures in the past five years.

b. Provide the quantifiable value proposition that the identification of any additional low priority leaks through the AMD is worth the additional cost of the AMD system.

Response:

a. The Company has not had problems identifying true gradable leaks using traditional tools measuring in the parts per million. Surveying in parts per billion through AMD, when fully implemented, will allow the Company to find more gradable leaks due to increased sensitivity of the technology. AMD will also reduce human error as it will direct surveyors in the field where a leak might exist rather than the random surveying methods currently used.

b. The primary value proposition for AMD is increased public safety and proving a method for which to measure the emissions rates of natural gas leaks. These value propositions have not been quantified.

Witness: Kristine A. Pascarello
Date: April 8, 2024

Question:

212. Refer to lines 11-23 on page 68 of Ms. Pascarello's direct testimony on the AMD. Please describe what information the Company has gathered from other gas utilities that have had the AMD in place for several years. Do these utilities believe that the large investment in the AMD was worth the value derived from the system? If yes, identify those utilities and where they see the value and how much.

Response:

The Company has met with peer utilities employing the same AMD technology to discuss AMD best practices. The Company has not engaged in conversations with peers around AMD cost/benefit or value decisions.

My reference to peer-to-peer communications at page 68 of my direct testimony was in connection with the selection of the third-party vendor. Multiple other gas operators across the US and world are using the same AMD technology for methane detection. When comparing industry offerings, the Company considered technology, software, precedence, and operating modes. With these areas of consideration, the Company selected the vendor that was best able to satisfy all 4 areas.

Witness: Kristine A. Pascarello
Date: April 8, 2024

Question:

213. Refer to lines18-26 on page 70 of Ms. Pascarello's direct testimony on the AMD. Please:

a. Confirm that the AMD detected possible leaks and not actual gas leaks.

b. Why does the Company need to refine the leak detection capabilities of the AMD to detect true gradable leaks when the system should be more effective in detecting actual gas leaks than the previous leak detection equipment.

c. Why does the new AMD application and hardware need to be complemented by the other systems identified on lines 24-26? What is the forecasted cost to implement this integration and what financial value will it provide?

Response:

a. The AMD technology does not confirm a leak. It is designed to detect the presence of a potential leak through highly sensitive methane/ethane detectors and geographically show a search area for a leak investigator to follow-up and confirm if a leak is present.

b. Refinement involves a feedback loop. Given the high sensitivity of the AMD technology, there is a need to refine the technology with actual investigation results data to ensure that future surveys show true gradable leaks.

c. AMD is one component of the leak survey and remediation process. AMD data is incorporated with GIS to spatially show where to focus the leak investigation and collect investigation data. The GIS data is or will be further connected with other platforms to complete the tracking and remediation process and to analyze system condition.

Witness: Kristine A. Pascarello
Date: April 8, 2024

Question:

214. Refer to Table 8 on page 72 of Ms. Pascarello's direct testimony on the AMD. Please:

a. Expand this table to include actual costs for 2023 and all costs from inception to completion by year. Provide it in Excel.

b. Identify what the amounts each year were spent on or will be spent on.

c. Provide a copy of the cost/benefit analysis in Excel with formulas intact and assumptions explained.

d. If the Commission approved cost recovery of this project as a litigated item in a previous rate case, provide the case number, order date, and page reference.

Response:

a. Please see attachment U21490-AG-CE-0373_Pascarello_ATT_1.

b. The capital amounts will be used to purchase Picarro Surveyor Units. Nine units have been/are projected to be purchased. The number of units are two, three, zero, one, and three in 2021 through 2025 respectively. The O&M amounts are for software licensing and conducting surveys.

c. The primary benefits of AMD technology are public safety and are not represented in a spreadsheet. This technology will enable the Company to find and prioritize the higher risk leaks to improve public safety. AMD will improve data and understanding of system risk, target higher risk areas for system improvements, and improve detection of methane. AMD will improve safety and reliability by aiding in a strategic and data driven approach to higher-risk leak identification and remediation. When used with risk-based and algorithm capabilities, it will deliver increased safety to the customer while also delivering higher quality, tracking, and cost management. Upon full implementation, the project is expected to improve affordability by reducing leak survey costs by reducing the amount of foot patrol needed while performing compliance leak survey. It also supports the Company's goal of net zero methane emissions by first time quantification and identification of large volume emission locations leading to prioritized remediation.

d. In addition to this case, this project was included in Case Nos. U-21148 and U-21308, both of which resulted in approved settlement agreements.

Witness: Kristine A. Pascarello
Date: April 8, 2024

U21490-AG-CE-0373_Pascarello_ATT_1

Table 8: AMD Actual and Projected Costs

	2021	2022	2023 Projected	2023 Preliminary Actual	2024 Projected	2025 Projected	Total
O&M	$ 122,874	$ 102,706	$ 232,834	$ 188,561	$ 199,596	$ 432,834	$ 1,046,571
Capital	$ 2,400,000	$ 4,635,000	$ -	$ -	$ 1,539,370	$ 4,771,746	$ 13,346,116

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Question:

215. Refer to lines 17-21 on page 72 of Ms. Pascarello's direct testimony on the AMD. Please confirm that the PHMSA Advisory Bulletin does not require the use of the AMD system and the previous equipment the Company used identified hazardous leaks. If not confirming, provide evidence otherwise.

Response:

PHMSA NPRM currently states that there will be a requirement to measure the emissions rates of natural gas leaks on distribution systems to classify/grade them. If that rule stands, AMD technology will be required as traditional technology cannot measure flow rates.

Witness: Kristine A. Pascarello
Date: April 8, 2024

The remainder of this exhibit consists of 78 pages PHMSA
Rules and Regulations

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA–2011–0023; Amdt. Nos. 191–26; 192–125]

RIN 2137–AE72

Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines. This final rule addresses congressional mandates, National Transportation Safety Board recommendations, and responds to public input. The amendments in this final rule address integrity management requirements and other requirements, and they focus on the actions an operator must take to reconfirm the maximum allowable operating pressure of previously untested natural gas transmission pipelines and pipelines lacking certain material or operational records, the periodic assessment of pipelines in populated areas not designated as ''high consequence areas,'' the reporting of exceedances of maximum allowable operating pressure, the consideration of seismicity as a risk factor in integrity management, safety features on in-line inspection launchers and receivers, a 6-month grace period for 7-calendar-year integrity management reassessment intervals, and related recordkeeping provisions.

DATES: The effective date of this final rule is July 1, 2020. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of July 1, 2020. The incorporation by reference of ASME/ANSI B31.8S was approved by the Director of the Federal Register as of January 14, 2004.

FOR FURTHER INFORMATION CONTACT: Technical questions: Steve Nanney, Project Manager, by telephone at 713–272–2855. General information: Robert Jagger, Senior Transportation Specialist, by telephone at 202–366–4361.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of the Regulatory Action

PHMSA believes that the current regulatory requirements applicable to gas pipeline systems have increased the level of safety associated with the transportation of gas. Still, incidents continue to occur on gas pipeline systems resulting in serious risks to life and property. One such incident occurred in San Bruno, CA, on September 9, 2010, killing 8 people, injuring 51, destroying 38 homes, and damaging another 70 homes (PG&E incident). In its investigation of the incident, the National Transportation Safety Board (NTSB) found among several causal factors that the operator, Pacific Gas and Electric (PG&E), had an inadequate integrity management (IM) program that failed to detect and repair or remove the defective pipe section. PG&E was basing its IM program on incomplete and inaccurate pipeline information, which led to, among other things, faulty risk assessments, improper assessment method selection, and internal assessments of the program that were superficial and resulted in no meaningful improvement in the integrity of the pipeline system nor the IM program itself.

The PG&E incident underscored the need for PHMSA to extend IM requirements and address other issues related to pipeline system integrity. In response, PHMSA published an ANPRM seeking comment on whether IM and other requirements should be strengthened or expanded, and other related issues, on August 25, 2011 (76 FR 53086).

The NTSB adopted its report on the PG&E incident on August 30, 2011, and issued several safety recommendations to PHMSA and other entities. Several of these NTSB recommendations related directly to the topics addressed in the 2011 ANPRM and are addressed in this final rule. Also, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act) was enacted on January 3, 2012. Several of the 2011 Pipeline Safety Act's statutory requirements related directly to the topics addressed in the 2011 ANPRM and are a focus of this rulemaking.

Another incident that influenced this rulemaking was the rupture of a gas transmission pipe operated by Columbia Gas near Sissonville, WV, on December 11, 2012. The escaping gas ignited, and fire damage extended nearly 1,100 feet along the pipeline right-of-way and covered an area roughly 820 feet wide. While there were no fatalities or serious injuries, three houses were destroyed by the fire, and several other houses were damaged. The ruptured pipe was one of three in the area that cross Interstate 77, and the incident closed the highway in both directions for 19 hours until a section of thermally damaged road surface approximately 800 feet long could be replaced. Following this incident, the NTSB finalized an accident report on February 19, 2014, issuing recommendations to PHMSA to include principal arterial roadways, including interstates, other freeways and expressways, and other principal arterial roadways as defined by the Federal Highway Administration, to the list of ''identified sites'' that establish a high consequence area (HCA) for the purposes of an operator's IM program.

On April 8, 2016, PHMSA published an NPRM to seek public comments on proposed changes to the gas transmission pipeline safety regulations (81 FR 20722). A summary of those proposed changes, and PHMSA's response to stakeholder feedback on the individual provisions, is provided below in section IV of this document (Analysis of Comments and PHMSA Response).

The purpose of this final rule is to increase the level of safety associated with the transportation of gas. PHMSA is finalizing requirements that address the causes of several recent incidents, including the PG&E incident, by clarifying and enhancing existing requirements. PHMSA is also addressing certain statutory mandates of the 2011 Pipeline Safety Act and NTSB recommendations. While the NPRM addressed 16 major topic areas, PHMSA believes the most efficient way to manage the proposals in the NPRM is to divide them into three rulemaking actions. PHMSA is finalizing the provisions in this final rule as a first step. PHMSA anticipates completing a second rulemaking to address the topics in the NPRM regarding repair criteria in HCAs and the creation of new repair criteria for non-HCAs, requirements for inspecting pipelines following extreme events, updates to pipeline corrosion control requirements, codification of a management of change process, clarification of certain other IM requirements, and strengthening IM assessment requirements.[1] A third rulemaking is expected to address requirements related to gas gathering lines that were proposed in the NPRM.[2]

B. Summary of the Major Provisions of the Regulatory Action in Question

Several of the amendments made in this rule are related to congressional legislation from the 2011 Pipeline Safety Act. The Act provides a 6-month grace period, with written notice, for the completion of periodic integrity management reassessments that otherwise would be completed no later than every 7 calendar years.[3] Another requirement is that operators explicitly consider and account for seismicity in identifying and evaluating potential threats.[4] The Act also requires operators to report exceedances of the maximum allowable operating pressure (MAOP) of gas transmission pipelines.[5] [6] PHMSA is incorporating these changes into the PSR at 49 CFR parts 190–199 in this final rule.

This rule also requires operators of certain onshore steel gas transmission pipeline segments to reconfirm the MAOP of those segments and gather any necessary material property records they might need to do so, where the records needed to substantiate the MAOP are not traceable, verifiable, and complete. This includes previously untested pipelines, which are commonly referred to as ''grandfathered'' pipelines, operating at or above 30 percent of specified minimum yield strength (SMYS). Records to confirm MAOP include pressure test records or material property records (mechanical properties) that verify the MAOP is appropriate for the class location.[7] Operators with missing records can choose one of six methods to reconfirm their MAOP and must keep the record that is generated by this exercise for the life of the pipeline. PHMSA has also created an opportunistic method by which operators with insufficient material property records can obtain such records. These physical material property and attribute records include the pipeline segment's diameter, wall thickness, seam type, grade (the minimum yield strength and ultimate tensile strength of the pipe), and Charpy V-notch toughness values (full-size specimen and based on the lowest operational temperatures),[8] if applicable or required. PHMSA considers ''insufficient'' material property records to be those records where the pipeline's physical material properties and attributes are not documented in traceable, verifiable, and complete records.

PHMSA is requiring operators to perform integrity assessments on certain pipelines outside of HCAs, whereas prior to this rule's publication, integrity assessments were only required for pipelines in HCAs. Pipelines in Class 3 locations, Class 4 locations, and in the newly defined ''moderate consequence areas'' (MCA) [9] must be assessed initially within 14 years of this rule's publication date and then must be reassessed at least once every 10 years thereafter. These assessments will provide important information to operators about the conditions of their pipelines, including the existence of internal and external corrosion and other anomalies, and will provide an elevated level of safety for the populations in MCAs while continuing to allow operators to prioritize the safety of HCAs. This action fulfills the section 5 mandate from the 2011 Pipeline Safety Act to expand elements of the IM requirements beyond HCAs where appropriate.

This rule also explicitly requires devices on in-line inspection (ILI), launcher or receiver facilities that can safely relieve pressure in the barrel before inserting or removing ILI tools, and requires the use of a device that can indicate whether the pressure has been relieved in the barrel or can otherwise prevent the barrel from being opened if the pressure is not relieved. PHMSA is finalizing this requirement in this final rule because it is aware of incidents where operator personnel have been killed or seriously injured due to pressure build-up at these stations.

C. Costs and Benefits

Consistent with Executive Order 12866, PHMSA has prepared an assessment of the benefits and costs of the final rule as well as reasonable alternatives. PHMSA estimates the annual costs of the rule to be approximately $32.7 million, calculated using a 7 percent discount rate. The costs reflect additional integrity assessments, MAOP reconfirmation, and ILI launcher and receiver upgrades.

PHMSA is publishing the Regulatory Impact Analysis (RIA) for this rule in the public docket. The table below

[1] RIN 2137–AF39.

[2] RIN 2137–AF38.

[3] 2011 Pipeline Safety Act § 5(e).

[4] 2011 Pipeline Safety Act § 29.

[5] 2011 Pipeline Safety Act § 23.

[6] MAOP means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

[7] PHMSA uses class locations throughout part 192 to provide safety margins and standards commensurate with the potential consequence of a pipeline failure based on the surrounding population. Class locations are defined at § 192.5. A Class 1 location is an offshore area or a class location unit with 10 or fewer buildings intended for human occupancy. A Class 2 location is a class location unit with more than 10 but fewer than 46 buildings intended for human occupancy. A Class 3 location is a class location unit with 46 or more buildings intended for human occupancy, and a Class 4 location is where buildings with 4-or-more stories above ground are prevalent.

[8] A Charpy V-notch impact test and its values indicate the toughness of a given material at a specified temperature and is used in fracture mechanics analysis.

[9] A MCA is defined in § 191.3 as an onshore area within a potential impact circle, as that term is defined in § 192.903, containing either (1) 5 or more buildings intended for human occupancy or (2) any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1.*

provides a summary of the estimated costs for the major provisions in this rulemaking (see the RIA for further detail on these estimates). PHMSA finds that the other final rule requirements will not result in incremental costs. PHMSA did not quantify the cost savings from material properties verification under the final rule compared to existing regulations. PHMSA also elected to not quantify the benefits of this rulemaking and instead discusses them qualitatively. PHMSA estimated total annual costs of the rule of $31.4 million using a 3 percent discount rate, and $32.7 million using a 7 percent discount rate.

SUMMARY OF ANNUALIZED COSTS, 2019–2039
[$2017 thousands]

Provision	Annualized cost	
	3% Discount rate	7% Discount rate
1. MAOP Reconfirmation & Material Properties Verification	$25,848	$27,899
2. Seismicity	0.00	0.00
3. Six-Month Grace Period for Seven Calendar-Year Reassessment Intervals	0.00	0.00
4. In-Line Inspection Launcher/Receiver Safety	27.4	37.5
5. MAOP Exceedance Reports	0.00	0.00
6. Strengthening requirements for assessment methods	0.00	0.00
7. Assessments outside HCAs	5,482	4,713
8. Related Records Provisions	0.00	0.00
Total	31,357	32,650

II. Background

A. Detailed Overview

Introduction

Recent significant growth in the nation's production and use of natural gas is placing unprecedented demands on the Nation's pipeline system, underscoring the importance of moving this energy product safely and efficiently. Changing spatial patterns of natural gas production and use and an aging pipeline network has made improved documentation and data collection increasingly necessary for the industry to make reasoned safety choices and for preserving public confidence in its ability to do so. Congress recognized these needs when passing the 2011 Pipeline Safety Act, calling for an examination of issues pertaining to the safety of the Nation's pipeline network, including a thorough application of the risk-based integrity assessment, repair, and validation system known as IM.[10]

This final rule advances the goals established by Congress in the 2011 Pipeline Safety Act and is consistent with the emerging needs of the natural gas pipeline system. This final rule also advances the important discussion about the need to adapt and expand risk-based safety practices. As some severe pipeline incidents have occurred in areas outside HCAs[11] where the application of IM principles are not required, and as gas pipelines continue to experience failures from causes that IM was intended to address, this conversation is increasingly important.

This final rule strengthens IM requirements, including to ensure operators select the appropriate inspection tool or tools to address the pertinent identified threats to their pipeline segments, and clarifies and expands recordkeeping requirements to ensure operators have and retain the basic physical and operational attributes and characteristics of their pipelines. Further, this final rule establishes requirements to periodically assess pipeline segments in locations outside of HCAs where the surrounding population is expected to potentially be at risk from an incident, which are defined in the rule as MCAs. Even though these pipeline segments are not within currently defined HCAs, they could be located in areas with significant populations. This change facilitates prompt identification and remediation of potentially hazardous defects while still allowing operators to make risk-based decisions on where to allocate their maintenance and repair resources.

Natural Gas Infrastructure Overview

The U.S. natural gas pipeline network is designed to transport natural gas to and from most locations in the lower 48 States. Approximately two-thirds of the lower 48 States depend almost entirely on the interstate transmission pipeline system for their supply of natural gas.[12] One can consider the Nation's natural gas pipeline infrastructure as three interconnected parts—gathering, transmission, and distribution—that together transport natural gas from the production field, where gas is extracted from underground, to its end users, where the gas is used as an energy fuel or chemical feedstock. This final rule applies only to gas transmission lines and does not address gas gathering or natural gas distribution infrastructure and its associated issues. Currently, there are over 300,000 miles of onshore gas transmission pipelines throughout the U.S.[13]

Transmission pipelines primarily transport natural gas from gas treatment plants and gathering systems to bulk customers, local distribution networks, and storage facilities. Transmission pipelines can range in size from several inches to several feet in diameter. They can operate over a wide range of pressures, from a relatively low 200 pounds per square inch gage (psig) to

[10] The IM regulations specify how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs that could, in the event of a leak or failure, affect high consequence areas in the United States. These areas include certain populated and occupied areas. See § 192.903.

[11] HCAs are defined at § 192.903. There are two methods that can be used to determine and HCA, the specific differences of which we do not address here. Very broadly and regardless of which method used, operators must calculate the potential impact radius for all points along their pipelines and evaluate corresponding impact circles to identify what populations are contained within each circle. Potential impact circles with 20 or more structures intended for human occupancy, or those circles with ''identified sites'' such as stadiums, playgrounds, office buildings, and religious centers, are defined as HCAs.

[12] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–28, April 2015.

[13] U.S. DOT Pipeline and Hazardous Materials Safety Administration Data as of 4/26/2018.

over 1,500 psig. They can be hundreds of miles long, and can operate within the geographic boundaries of a single State, or cross one or more State lines.

Regulatory History

PHMSA and its State partners regulate and enforce the minimum Federal safety standards authorized by statute [14] and codified in the PSR for jurisdictional [15] gas gathering, transmission, and distribution systems.

Federal regulation of gas pipeline safety began in 1968 with the creation of the Office of Pipeline Safety and the passage of the Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90–481). The Office of Pipeline Safety issued interim minimum Federal safety standards for gas pipeline facilities and the transportation of natural and other gas by pipeline on November 13, 1968, and subsequently codified broad-based gas pipeline regulations on August 19, 1970 (35 FR 13248). The PSR were revised several times over the following decades to address different aspects of natural gas transportation by pipeline, including construction standards, pipeline materials, design standards, class locations, corrosion control, and MAOP.

In the mid-1990s, following models from other industries such as nuclear power, PHMSA started to explore whether a risk-based approach to regulation could improve safety of the public and reduce damage to the environment. During this time, PHMSA found that many operators were performing forms of IM that varied in scope and sophistication but that there were no uniform standards or requirements.

PHMSA began developing minimum IM regulations for both hazardous liquid and gas transmission pipelines in response to a hazardous liquid accident in Bellingham, WA, in 1999 that killed 3 people and a gas transmission incident in Carlsbad, NM, in 2000 that killed 12. PHMSA finalized IM regulations for gas transmission pipelines in a 2003 final rule.[16] The IM regulations are intended to provide a structure to operators to focus resources on improving pipeline integrity in the areas where a failure would have the greatest impact on public safety. The IM final rule accelerated the integrity assessment of pipelines in HCAs, improved IM systems, and improved the government's ability to review the adequacy of IM plans.

The IM regulations require that operators conduct comprehensive analyses to identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs. Approximately 7 percent of onshore gas transmission pipeline mileage is located in HCAs.[17] PHMSA and State inspectors review operators' IM programs and associated records to verify that the operators have used all available information about their pipelines to assess risks and take appropriate actions to mitigate those risks.

Since the implementation of the IM regulations, sweeping changes in the natural gas industry have caused significant shifts in supply and demand, and the Nation's pipeline network faces increased pressures from these changes as well as from the increased exposure caused by a growing and geographically dispersing population. Also, long-identified pipeline safety issues, some of which IM set out to address, remain problems. A records search following the PG&E incident required by Congress in the 2011 Pipeline Safety Act, showed that some pipeline operators do not have the records they need to substantiate the current MAOP of their pipelines, as required under existing regulations, and lacked other critical information needed to properly assess risks and threats and perform effective IM.[18] PHMSA's inspection experience indicates pipelines continue to be vulnerable to failures stemming from outdated construction methods or materials. Finally, some severe pipeline incidents have occurred in areas outside HCAs where the application of IM principles is not required.

Following the significant pipeline incident in 2010 at San Bruno, CA, in which 8 people died and more than 50 people were injured, Congress charged PHMSA with improving the IM regulations. Additionally, the NTSB and Government Accountability Office (GAO) issued recommendations regarding IM.[19] Comments in response to a 2011 ANPRM on these and related topics suggested there were many common-sense improvements that could be made to IM, as well as a clear need to extend certain IM provisions to pipelines outside of HCAs that were not covered by the IM regulations. A large portion of the transmission pipeline industry has voluntarily committed to extending certain IM provisions to non-HCA pipe, which demonstrates a common understanding of the need for this strategy.

Through this final rule, PHMSA is making improvements to IM and is improving the ability of operators to engage in a long-range review of risk management and information needs, while also accounting for a changing landscape and a changing population.

Supply Changes

The U.S. natural gas industry increased production dramatically between 2005 and 2017, from 19.5 trillion cubic feet per year to 28.8 trillion cubic feet per year.[20] This growth was enabled by the production of ''unconventional'' natural gas supplies using improved technology to extract gas from low permeability shales. The increased use of directional drilling [21] and improvements to a long-existing industrial technique—hydraulic fracturing,[22] which began as an experiment in 1947—made the recovery of unconventional natural gas easier and economically viable. This has led to decreased prices and increased use of natural gas, despite a reduction in the production of conventional natural gas of about 14 billion cubic feet per day. Unconventional shale gas production now accounts for nearly 70 percent of overall gas production in the U.S.

Growth in unconventional natural gas production has shifted production away from traditionally gas-rich regions towards inland shale gas regions. To illustrate, in 2004, wells in the Gulf of Mexico's produced 5,066,000 million

[14] Title 49, United States Code, Subtitle VIII, Pipelines, Sections 60101, *et. seq.*

[15] Typically, onshore pipelines involved in the ''transportation of gas''—see 49 CFR 192.1 and 192.3 for detailed applicability.

[16] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines).'' 68 FR 69778; December 15, 2003. Corrected April 6, 2004 (69 FR 18227) and May 26, 2004 (69 FR 29903).

[17] Per PHMSA's 2018 Annual Report, accessed April 9, 2019, 20,435 of the 301,227 miles of gas transmission pipelines are classified as being in HCAs.

[18] An effective IM program requires operators to analyze many data points regarding threats to their systems in addition to pipe attributes, including, but not limited to, construction data (year of installation, pipe bending method, joining method, depth of cover, coating type, pressure test records, etc.), operational data (maximum and minimum operating pressures, leak and failure history, corrosion monitoring, excavation data, corrosion surveys, ILI data, etc.).

[19] More information on the NTSB recommendations being addressed in this rule are discussed in further detail in Section II. D. of this document ''National Transportation Safety Board Recommendations.'' See also, GAO–06–946, Natural Gas Pipeline Safety: Integrity Management Benefits Public Safety, but Consistency of Performance Measures Should be Improved,'' September 8, 2006.

[20] U.S. Department of Energy, Energy Information Administration, ''U.S. Natural Gas marketed Production'' *https://www.eia.gov/dnav/ng/hist/n9050us2a.htm,* accessed 6/28/18.

[21] Directional drilling is the practice of drilling non-vertical wells.

[22] The extraction of oil or gas deposits performed by forcing open fissures in subterranean rocks by introducing liquid at high pressures.

cubic feet of natural gas per year (Mcf/year), approximately 20 percent of the Nation's natural gas production at the time. By 2016, that number had fallen to 1,220,000 Mcf/year, and approximately 4 percent of natural gas production in the U.S. During that same period, Pennsylvania's share of production grew from 197,217 Mcf/year to 5,463,783 Mcf/year, or approximately 17 percent of total natural gas production in the U.S.[23] [24] An analysis conducted by the Department of Energy's Office of Energy Policy and Systems Analysis projects that the most significant increases in production through 2030 will occur in the Marcellus and Utica Basins in the Appalachian Basin,[25] and natural gas production is projected to grow from the 2015 levels of 66.5 Bcf/d to more than 93.5 Bcf/d.[26]

Demand Changes

The increase in domestic natural gas production has led to lower average natural gas prices.[27] In 2004, the outlook for natural gas production and demand growth was weak. Monthly average spot prices at Henry Hub [28] were high based on historic comparison of prices, fluctuating between $4 per million British thermal units (Btu) and $7 per million Btu. Prices rose above $11 per million Btu for several months in both 2005 and 2008.[29] Since 2008, after production shifted to onshore unconventional shale resources, and price volatility fell away following the Great Recession, natural gas has traded between about $2 per million Btu and $5 per million Btu.[30]

These low prices have fueled consumption growth and changes in markets and spatial patterns of consumption. A shift towards natural gas-fueled electric power generation, cleaner than other types of fossil fuels, is helping to serve the needs of the Nation's growing population, and increased gas production and lower domestic prices have created opportunities for international export.

Plentiful domestic natural gas supply and comparatively low natural gas prices have changed the economics of electric power markets.[31] To accommodate recent growth and expected future growth in natural gas-fueled power, changes in pipeline infrastructure will be needed, including flow reversals of existing pipelines; additional lines to gas-fired generators; looping of existing networks, where multiple pipelines are laid parallel to one another along a single right-of-way to increase the capacity of a single system; and, potentially, new pipelines as well.

Increasing Pressures on the Existing Pipeline System Due to Supply and Demand Changes

Despite the significant increase in domestic gas production and the widespread distribution of domestic gas demand, significant flexibility and capacity in the existing transmission system mitigates the level of pipeline expansion and investment required. Some of the new gas production is located near existing or emerging sources of demand, which reduces the need for additional natural gas pipeline infrastructure. In many instances where new natural gas transmission capacity is needed, the network is being expanded by pipeline investments to enhance network capacity on existing lines rather than increasing coverage through new infrastructure. Additionally, operators have avoided building new pipelines by increasing pipeline diameters or operating pressures. In short, the nation's existing pipeline system is facing the brunt of this dramatic increase in natural gas supply and the shifting energy needs of the country.

In cases where use of the existing pipeline network is high, the next most cost-effective solution is to add capacity to existing lines via compression.[32] Compression requires infrastructure investment in the form of more compressor stations along the pipeline route, but it can be less costly, faster, and simpler for market participants in comparison to building a new pipeline. Adding compression, however, raises pipeline operating pressures and can expose previously hidden defects.

New pipeline projects have been proposed to address pending supply constraints and higher prices. However, gaining public acceptance for natural gas pipeline construction has proved to be a substantial challenge. Pipeline expansion and construction projects often face significant challenges in determining feasible right-of-ways and developing community support for the projects.

Data Challenges

Operators and regulators must have an intimate understanding of the threats to, and operations of, their entire pipeline system. Data gathering and integration are important elements of good IM practices, and while operators have made many strides over the years to collect more and better data, several data gaps still exist. Ironically, the comparatively positive safety record of the Nation's gas transmission pipelines to date makes it harder to quantify some of these gaps. Over the 20-year period of 1998–2017, transmission facilities accounted for 50 fatalities and 179 injuries, or about one-sixth to one-seventh of the total fatalities and injuries caused by natural gas pipeline incidents in the U.S.[33] Given the relatively limited number of significant incidents that occur, it can be challenging to project the possible impact of low-probability but high-consequence events. See the RIA included in the public docket for a more detailed analysis of key types of incidents that may be mitigated by this final rule.

On September 9, 2010, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline owned and operated by PG&E ruptured in a residential area of San Bruno, CA. The natural gas that was released subsequently ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.

The PG&E incident exposed several problems in the way data on pipeline conditions is collected and managed, showing that the operator had inadequate records regarding the physical and operational characteristics of their pipelines. These records are necessary for the correct setting and validation of MAOP, which is critically

[23] U.S. Department of Energy, Energy Information Administration, ''Gulf of Mexico—Offshore Natural Gas Withdrawals,'' *https://www.eia.gov/dnav/ng/hist/na1060_r3fmtf_2a.htm,* accessed 6/28/18.

[24] U.S. Department of Energy, Energy Information Administration, ''Pennsylvania Natural Gas Gross Withdrawals,'' *https://www.eia.gov/dnav/ng/hist/n9010pa2a.htm,* accessed 6/28/18.

[25] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–28, April 2015.

[26] *Id.,* at NG–6.

[27] *Id.,* at NG–11.

[28] Henry Hub is a Louisiana natural gas distribution hub where conventional Gulf of Mexico natural gas can be directed to gas transmission lines running to different parts of the country. Gas bought and sold at the Henry hub serves as the national benchmark for U.S. natural gas prices. (*Id.,* at NG–29, NG–30).

[29] Energy Information Administration, Natural Gas Spot and Futures Prices, *http://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm,* retrieved August 2018.

[30] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–11, April 2015.

[31] *Id.,* at NG–9.

[32] Gas can be reduced in volume by increasing its pressure. Therefore, operators can pack more gas into their lines if they can increase the pressure of the gas being transported.

[33] PHMSA, Pipeline Incident 20-Year Trends, *http://www.phmsa.dot.gov/pipeline/library/data-stats/pipelineincidenttrends.*

important for providing an appropriate margin of safety to the public.

Much of operator data is obtained through the assessments and other safety inspections required by IM regulations. However, this testing can be expensive, and the approaches to obtaining data that are most efficient over the long term may require significant upfront costs to modernize pipes and make them suitable for automated inspection. As a result, there continue to be data gaps that make it hard to fully understand the risks to and the integrity of the Nation's pipeline system.

To evaluate a pipeline's integrity, operators generally choose between three methods of testing a pipeline: Inline inspection (ILI), pressure testing, and direct assessment (DA). In 2017, PHMSA estimates that about two-thirds of gas transmission interstate pipeline mileage was suitable for ILI, compared to only about half of intrastate pipeline mileage, and therefore, intrastate operators use more pressure testing and DA than interstate operators.

ILIs are performed using tools, referred to as ''smart pigs,'' which are usually pushed through a pipeline by the pressure of the product being transported. As the tool travels through the pipeline, it identifies and records potential pipe defects or anomalies. Because these tests can be performed with product in the pipeline, the pipeline does not have to be taken out of service for testing to occur, which can prevent excessive cost to the operator and possible service disruptions to consumers. Further, unlike pressure testing, ILI does not risk destroying the pipe, and it is typically less costly to perform on a per-unit basis than other assessment methods.

Pressure tests, also known as hydrostatic tests, are used by pipeline operators as a means to determine the integrity (or strength) of the pipeline immediately after construction and before placing the pipeline in service, as well as periodically during a pipeline's operating life. In a pressure test, water or an alternative test medium inside the pipeline is pressurized to a level greater than the normal operating pressure of the pipeline. This test pressure is held for a number of hours to ensure there are no leaks in the pipeline.

Direct assessment is the visual evaluation of a pipeline at a sample of locations along the line to detect corrosion threats, dents, and stress corrosion cracking of the pipe body and seams. In general, corrosion direct assessments are carried out by performing four steps. Operators will review records and other data, then inspect the pipeline through assessments that do not require excavation or use mathematical models and environmental surveys to find likely locations on a pipeline where corrosion is most likely to occur. For external corrosion, operators must use two or more complementary indirect assessment tools, including, for example, close interval surveys, direct current voltage gradient surveys, and alternating current voltage gradient surveys, to determine potential areas of corrosion to examine. For internal corrosion, operators must analyze data to establish whether water was present in the pipe, determine the locations where water would likely accumulate, and provide for a detailed examination and evaluation of those locations. Areas identified where corrosion may be occurring are then excavated, examined visually, and remediated as necessary. Operators also perform a post-assessment on segments where corrosion direct assessments are used to evaluate the effectiveness of the technique and determine re-assessment intervals as needed.[34]

For cracking, operators collect and analyze data to determine whether the conditions for stress corrosion cracking are present, prioritize potentially susceptible segments of pipelines, and select specific sites for examination and evaluation. A DA would then evaluate the presence of stress corrosion cracking and determine its severity and prevalence. Operators are required to repair anomalies, if found, and determine further mitigation requirements as necessary.

Direct assessment can be prohibitively expensive to use on a wide scale and may not give an accurate representation of the condition of lengths of entire pipeline segments when the high expense leads the operator to select an insufficient number of observations. Further, as DA can only be used to validate specific threats, an operator that relies solely on a DA without performing a thorough risk analysis or running multiple tools specific to multiple threats might be leaving other threats unremediated in their pipelines.

Ongoing research and industry response to the ANPRM [35] and NPRM [36] indicate that ILI and spike hydrostatic pressure testing [37] is more effective than DA for identifying pipe conditions that are related to stress corrosion cracking defects. Regulators and operators agree that improving ILI methods as an alternative to hydrostatic testing is better for risk evaluation and management of pipeline safety. Hydrostatic pressure testing can result in substantial costs, occasional disruptions in service, and substantial methane emissions due to the routine evacuation of natural gas from pipelines prior to tests. Further, many operators prefer not to use hydrostatic pressure tests because it can be destructive.[38] ILI testing can obtain data along a pipeline not otherwise obtainable via other assessment methods, although this method also has certain limitations.[39]

This final rule expands the range of permissible assessment methods and incorporates new guidelines to help operators in the selection of appropriate assessment methods. Promoting the use of ILI technologies, combined with further research and development by PHMSA as well as stakeholders to make ILI testing more accurate, is expected to drive innovation in pipeline integrity testing technologies that leads to improved safety and system reliability through better data collection and assessment.

Flow Reversals, Product Changes, and Manufacturing Defects

Significant growth of production outside the Gulf Coast region—especially in Pennsylvania and Ohio [40]—is causing a reorientation of the Nation's transmission pipeline network. The most significant of these changes will require reversing flows on pipelines to move gas from the Marcellus and Utica shale formations to the southeastern Atlantic region and the Midwest.

Reversing a pipeline's flow can cause added stress on the system due to changes in gas pipeline pressure and temperature, which can increase the risk

[34] See PHMSA's fact sheet on DA at *https://primis.phmsa.dot.gov/Comm/FactSheets/FSdirectAssessmentGas.htm.*

[35] ''Pipeline Safety: Safety of Gas Transmission Pipelines—Advanced Notice of Proposed Rulemaking,'' 76 FR 5308; August 25, 2011.

[36] ''Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines,'' 81 FR 20722; April 8, 2016.

[37] A ''spike'' hydrostatic pressure test is typically used to resolve cracks that might otherwise grow during pressure reductions after hydrostatic tests or as the result of operational pressure cycles.

[38] National Transportation Safety Board, ''Pacific Gas and Electric Company; Natural Gas Transmission Pipeline Rupture and Fire; San Bruno, California; September 9, 2010,'' *Pipeline Accident Report NTSB/PAR–11–01,* Page 96, 2011.

[39] For example, ILI tools are ideal for gathering certain information about the physical condition of the pipe, including corrosion, deformations, or cracking. However, ILI technology cannot reliably detect other conditions, such as coating damage or environmental issues.

[40] U.S. Energy Information Administration, ''Annual Energy Outlook 2019,'' p. 78—Dry shale gas production by region. *https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf*

of internal corrosion. Occasional failures on natural gas transmission pipelines have followed operational changes that include flow reversals and product changes.[41] Operators have recently submitted proposed flow reversals and product changes on gas transmission lines. In response to this phenomenon, PHMSA issued an Advisory Bulletin in 2014 notifying operators of the potentially significant impacts such changes may have on the integrity of a pipeline and recommended additional actions operators should consider performing before, during, and after flow reversals, product changes, and conversions to service, including notifications, operations and maintenance requirements, and IM requirements.[42]

Data indicates that some pipelines are vulnerable to issues stemming from outdated construction methods or materials. Some gas transmission infrastructure was made before the 1970s using techniques that have proven to contain latent defects due to the manufacturing process. For example, pipe manufactured using low frequency electric resistance welding is susceptible to seam failure. Because these pipelines were installed before the Federal gas regulations were issued, many of those pipes were exempted from certain regulations, most notably the requirement to pressure test the pipeline segment immediately after construction and before placing the pipeline into service. A substantial amount of this type of pipe is still in service.[43] The IM regulations include specific requirements for evaluating such pipe if located in HCAs, but infrequent-yet-severe failures that are attributed to longitudinal seam defects continue to occur. The NTSB's investigation of the PG&E incident in San Bruno determined that the pipe failed due to a similar defect, a fracture originating in the partially welded longitudinal seam of the pipe. According to PHMSA's accident and incident database, between 2010 and 2017, 30 other reportable incidents were attributed to seam failures, resulting in over $18 million of reported property damage.

Protecting the Safety and Integrity of the Nation's Pipeline System Beyond HCAs

The current IM program improves pipeline operators' ability to identify and mitigate the risks to their pipeline systems. IM regulations require that operators adopt procedures and processes to identify HCAs; determine likely threats to the pipeline within the HCA; evaluate the physical integrity of the pipe within the HCA; and repair, remediate, or monitor any pipeline defects found based on severity. Because these procedures and processes are complex and interconnected, effective implementation of an IM program relies on continual evaluation and data integration.

HCAs were first defined on August 6, 2002,[44] providing concentrations of populations with corridors of protection spanning 300, 660, or 1,000 feet, depending on the diameter and MAOP of the particular pipeline.[45] In a later NPRM,[46] PHMSA proposed changes to the definition of a HCA by introducing the concept of a covered segment, which PHMSA defined as the length of gas transmission pipeline that could potentially impact an HCA.[47] Previously, only distances from the pipeline centerline related to HCA definitions. PHMSA also proposed using Potential Impact Circles (PIC), Potential Impact Zones, and Potential Impact Radii (PIR) to identify covered segments instead of a fixed corridor width. The final Gas Transmission Pipeline Integrity Management Rule, incorporating the new HCA definition using the PIR and PIC concepts, was issued on December 15, 2003.[48]

The PG&E incident in 2010 motivated a comprehensive reexamination of gas transmission pipeline safety. In response to the PG&E incident, Congress passed the 2011 Pipeline Safety Act, which directed PHMSA to reexamine many of its safety requirements, including the expansion of IM regulations for transmission pipelines.

Further, both the NTSB and the GAO issued several recommendations to PHMSA to improve its IM program and pipeline safety. The NTSB noted in a 2015 study[49] that IM requirements have reduced the rate of failures due to deterioration of pipe welds, corrosion, and material failures. However, the NTSB noted that pipeline incidents in HCAs due to other factors increased between 2010 and 2013, and the overall occurrence of gas transmission pipeline incidents in HCAs has remained stable. Since 2013 there have been an average of 9 incidents within HCAs, which is below a peak of 12 incidents per year in 2012 and 2013, but still higher than the number of incidents in 2010 and 2011. The NTSB also found many types of basic data necessary to support comprehensive probabilistic modeling of pipeline risks are not currently available.

Looking at Risk Beyond HCAs

PHMSA posed a series of questions to the public in the context of an August 25, 2011, ANPRM titled ''Safety of Gas Transmission Pipelines'' (76 FR 53086), including whether the regulations governing the safety of gas transmission pipelines needed changing. In particular, PHMSA asked whether to add prescriptive language to IM requirements, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. PHMSA sought comment on the definition of an HCA and whether additional restrictions should be placed on the use of DA as an IM assessment method. PHMSA also requested comment on non-IM requirements, including valve spacing and installation, corrosion control, and whether regulations for gathering lines needed to be modified.

PHMSA received 103 submissions containing thousands of comments in response to the ANPRM, which are summarized in more detail below. This feedback helped identify a series of proposed improvements to IM, including improvements to assessment goals such as integrity verification, MAOP verification, and material documentation; adjusted repair criteria; clarified protocol for identifying threats,

[41] On September 29, 2013, the Tesoro High Plains pipeline leaked 20,000 barrels of crude oil in a North Dakota field. The location of pressure and flow monitoring equipment had not been changed to account for the reversed flow. On March 19, 2013, Exxon's Pegasus pipeline failed; the flow on that pipeline was reversed in 2006.

[42] ''Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes, and Conversion to Service,'' *ADB PHMSA–2014–0040,* 79 FR 56121; September 18, 2014.

[43] Currently, PHMSA's data shows that roughly 168,000 of the Nation's 301,000 miles of onshore gas transmission pipelines were installed prior to the 1970 requirement for hydrostatic pressure testing. See *https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages.*

[44] ''Pipeline Safety: High Consequence Areas for Gas Transmission Pipelines,'' *Final rule,* 67 FR 50824; August 6, 2002.

[45] The influence of the existing class location concept on the early definition of HCAs is evident from the use of class locations themselves in the definition, and the use of fixed 660 ft. distances, which corresponds to the corridor width used in the class location definition. This concept was later significantly revised, as discussed later, in favor of a variable corridor width based on case-specific pipe size and operating pressure.

[46] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),'' *Notice of Proposed Rulemaking,* 68 FR 4278; January 28, 2003.

[47] HCA and PIR definitions are in 49 CFR 192.903.

[48] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),'' *Final rule,* 68 FR 69778; December 15, 2003.

[49] National Transportation Safety Board, ''Safety Study: Integrity Management of Gas Transmission Pipelines in High Consequence Areas,'' *NTSB SS–15/01,* January 27, 2015.

risk assessments and management, and prevention and mitigation measures; expanded and enhanced corrosion control; requirements for inspecting pipelines after incidents of extreme weather; and new guidance on how to calculate MAOP in order to set operating parameters more accurately and predict the risks of an incident. PHMSA published an NPRM on April 8, 2016 (81 FR 20722), which is discussed in more detail below.

Many of these aspects of IM have been an integral part of PHMSA's expectations since the inception of the IM program. As specified in the first IM rule, PHMSA expects operators to start with an IM framework, evolve a more detailed and comprehensive IM program, and continually improve their IM programs as they learn more about the IM process and the material condition of their pipelines through integrity assessments.

Section 23 of the 2011 Pipeline Safety Act required PHMSA to have pipeline operators conduct a records verification to ensure that their records accurately reflect the physical and operational characteristics of their pipelines in certain HCAs and class locations, and to confirm the established MAOP of those pipelines. Based on the data received from operators following the records verification, incidents that have occurred in non-HCA areas, and other knowledge gained since the 2011 Pipeline Safety Act was passed, PHMSA has become increasingly concerned that a rupture on the scale of San Bruno, with the potential to cause death and serious injury, as well as damage to the environment or the disruption of commerce, could occur elsewhere on the Nation's pipeline system in both HCA and non-HCA pipeline segments. There have been several recent incidents in non-HCAs that show significant incidents can occur in non-HCAs. For example, on December 14, 2007, two men were driving in a pickup truck on Interstate 20 near Delhi, LA, when a 30-inch gas transmission pipeline owned by Columbia Gulf Transmission Company ruptured. One of the men was killed, and the other was injured.

Further, on December 11, 2012, a 20-inch-diameter gas transmission line operated by Columbia Gas Transmission Company ruptured about 106 feet west of Interstate 77 (I–77) in Sissonville, WV. An area of fire damage about 820 feet wide extended nearly 1,100 feet along the pipeline right-of-way. Three houses were destroyed by the fire, and several other houses were damaged. Reported losses, repairs, and upgrades from this incident totaled over $8.5 million, and major transportation delays occurred. I–77 was closed in both directions because of the fire and resulting damage to the road surface. The northbound lanes were closed for approximately 14 hours, and the southbound lanes were closed for approximately 19 hours while the road was resurfaced, causing delays to both travelers and commercial shipping.

Finally, on April 29, 2016, an incident occurred on a Texas Eastern Transmission Corporation gas transmission line operated by Spectra Energy near Delmont, PA, which is approximately 25 miles away from Pittsburgh, PA. The explosion seriously injured one person, destroyed a house, damaged three other homes and vehicles outside, and caused the evacuation of nine other homes in the area. Even though the pipeline was in a Class 1 rural area, it still had a significant impact on the local population.

The Nation's population is growing, moving, and dispersing, leading to changes in population density that can affect the class location of a pipeline segment, as well as whether it is in an HCA. The definition of HCA is not necessarily an accurate reflection of whether an incident will have an impact on people. Requiring assessment and repair criteria for pipelines that, if ruptured, could pose a threat to areas where any people live, work, or congregate would improve public safety and would improve public confidence in the Nation's natural gas pipeline system.

Some pipeline operators have said they are already moving towards expanding the protections of IM beyond HCAs. In 2012, the Interstate Natural Gas Association of America (INGAA) issued a ''Commitment to Pipeline Safety,'' [50] underscoring its efforts towards a goal of zero incidents, a committed safety culture, a pursuit of constant improvement, and applying IM principles on a system-wide basis. To accomplish this goal, INGAA's members committed to performing actions that include applying risk management beyond HCAs; raising the standards for corrosion management; demonstrating ''fitness for service'' on pre-regulation pipelines; and evaluating, refining, and improving operators' ability to assess and mitigate safety threats. These actions aim to extend protection to people who live near pipelines but not within defined HCAs. Further, this final rule takes important steps toward developing a comprehensive approach for the entire industry by finalizing requirements for assessments outside of HCAs.

This final rule implements risk management standards that most accurately target the safety of communities while also providing sufficient ability to prioritize areas of greatest possible risk and impact.

Given the results of incident investigations, IM considerations, and the feedback from the ANPRM and the NPRM, PHMSA has determined it is appropriate to improve aspects of the current IM program and codify requirements for additional gas transmission pipelines to receive integrity assessments on a periodic basis to monitor for, detect, and remediate pipeline defects and anomalies. In addition, to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while balancing the cost of identifying such locations, PHMSA based the requirements for identifying those locations on effective processes already being implemented by pipeline operators and that protect people on a risk-prioritized basis.

Establishing integrity assessment requirements for non-HCA pipeline segments is important for providing safety to the public. Although those pipeline segments are not within defined HCAs, they will usually be in populated areas, and pipeline accidents in these areas may cause fatalities, significant property damage, or disrupt livelihoods. This final rule adopts a newly defined definition for MCAs to identify additional non-HCA pipeline segments that would require integrity assessments, thus assuring the timely discovery and repair of pipeline defects in MCA segments that could potentially impact people, property, or the environment. At the same time, operators can allocate their resources to HCAs on a higher-priority basis.

B. Pacific Gas and Electric Incident of 2010

On September 9, 2010, a 30-inch-diameter segment of a gas transmission pipeline owned and operated by PG&E ruptured in a residential neighborhood in San Bruno, CA, producing a crater approximately 72 feet long by 26 feet wide. The segment of pipe that ruptured weighed approximately 3,000 pounds, was 28 feet long, and was found 100 feet

[50] Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations to Mike Israni, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, dated January 20, 2012, ''*Safety of Gas Transmission Pipelines,* Docket No. PHMSA–2011–0023.'' INGAA represents companies that operate approximately 65 percent of the gas transmission pipelines, but INGAA does not represent all pipeline operators subject to 49 CFR part 192.

south of the crater. Over the course of the incident, 47.6 million standard cubic feet of natural gas was released. The escaping gas ignited, and the resultant fire destroyed 38 homes, damaged another 70, killed 8 people, injured approximately 60 people (10 seriously), destroyed or damaged 74 vehicles, and caused the evacuation of over 300 more people. The initial 911 calls described the fire as a ''gas station explosion'' and a ''possible airplane crash.'' After 91 minutes, PG&E was able to shut off the flow of gas to the rupture site, which allowed firefighters to approach the rupture site and begin containment efforts. Firefighting operations continued for 2 days; more than 900 emergency responders from San Bruno and surrounding areas were part of the emergency response, 600 of which were firefighters and emergency medical services personnel.[51]

The NTSB, in its pipeline accident report for the incident, determined that the probable cause of the accident was PG&E's inadequate quality assurance and control when it relocated the line in 1956 and an inadequate IM program. The NTSB determined that PG&E's IM program was deficient and ineffective because it was based on incomplete and inaccurate pipeline information, did not consider the pipeline's design and materials contribution to the risk of a pipeline failure, and failed to consider the presence of previously identified welded seam cracks as part of its risk assessment. These deficiencies resulted in the selection of an examination method that could not detect welded seam defects and led to internal assessments of PG&E's IM program that were superficial and resulted in no improvements. Ultimately, this inadequate IM program failed to detect and repair or remove the defective pipe section.

The NTSB found that PG&E's inaccurate geographic information system records at the time of the incident indicated that the ruptured segment was constructed from 30-inch-diameter seamless API 5L X42 steel pipe. However, seamless pipe has never been available in 30-inch diameter. According to PG&E employees who testified during the investigation, all 30-inch pipe purchased by PG&E at that time would have been double submerged arc welded, which has been found in cases to be susceptible to weld failure. This inaccuracy was compounded with the discovery that the material code from the journal voucher that PG&E's records were originally composed from erroneously indicated the ruptured segment was X52 grade pipe (52,000 pounds per square inch (psi)), not X42 grade pipe (42,000 psi). X52 pipe has a higher minimum yield strength than X42 pipe,[52] and incorporating such values into MAOP calculations would produce values that would be inconsistent with the pipeline's actual MAOP. PG&E also could not produce any design, material, or construction specifications from the 1956 construction project. In short, no one from PG&E could reliably determine what type of pipe was in the ground that ruptured.

The NTSB also noted that PHMSA's exemption of pipelines installed before 1970 from the regulatory requirement for pressure testing, which likely would have detected the installation defects, was a contributing factor to the accident. When the initial Federal minimum safety standards for natural gas transmission pipelines were finalized in 1970, an exemption was carved out for pre-1970s pipelines from the requirement for a post-construction hydrostatic pressure test. This exemption was not proposed in any of the NPRMs that preceded the initial regulations and was based on an assertion from the Federal Power Commission[53] that ''there are thousands of miles of jurisdictional interstate pipelines installed prior to 1952,[54] in compliance with the then-existing codes, that could not continue to operate at their present pressure levels and be in compliance with [the proposed MAOP determination requirements].''[55] Upon reviewing the operating record of interstate pipeline companies, the Commission found ''no evidence that would indicate a material increase in safety would result from requiring wholesale reductions in the pressure of existing pipelines which have been proven capable of withstanding present operating pressures through actual operation.'' The Office of Pipeline Safety, at the time, determined it ''[did] not now have enough information to determine that existing operating pressures are unsafe,'' and taking into account the statements from the Federal Power Commission, included the ''grandfather'' clause in the final rule to permit the continued operation of pipelines at the highest pressure to which the pipeline had been subjected during the 5 years preceding July 1, 1970.[56][57] The 5-year limit was prescribed so that operators would be prevented from ''using a theoretical MAOP which may have been determined under some formula used 20, 30, or 40 years ago.''[58]

The NTSB noted in its investigation that the ''grandfathering'' of the ruptured line resulted in missed opportunities to detect the defective pipe, as a hydrostatic pressure test to the prescribed levels for a Class 3 location would likely have exposed the defective pipe that led to the accident. Following the PG&E incident, the California Public Utilities Commission (CPUC) required PG&E and other gas transmission pipeline operators regulated by CPUC to either hydrostatically pressure test or replace certain transmission pipelines with grandfathered MAOPs, stating that gas transmission pipelines ''must be brought into compliance with modern standards for safety'' and that ''historic exemptions must come to an end.''[59] Currently, PHMSA's data shows that roughly 168,000 of the Nation's 301,000 miles of onshore gas transmission pipelines were installed prior to the 1970 requirement for hydrostatic pressure testing.[60]

On April 1, 2014, the Department of Justice indicted PG&E for multiple criminal violations of part 192 for the 2010 incident in San Bruno, CA. The trial began on June 14, 2016, and after a 5 ½ week trial, a Federal jury found PG&E guilty of knowingly and willingly violating 5 sections of PHMSA's IM regulations and obstructing the NTSB investigation.

Specifically, with respect to the Federal Pipeline Safety Regulations, the jury found that between 2007 and 2010, PG&E knowingly and willfully failed to: (1) Gather and integrate existing data and information that could be relevant to identifying and evaluating potential threats on covered pipeline segments; (2) identify and evaluate all potential

[51] National Transportation Safety Board. 2011. *Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010.* Pipeline Accident Report NTSB/PAR–11/01. Washington, DC.

[52] 52,000 psi vs. 42,000 psi.

[53] The predecessor of the Federal Energy Regulatory Commission.

[54] Between 1935 and 1951, the B31 Code only required a pipeline be tested to a pressure of 50 psig in excess of the pipeline's proposed MAOP. The 1970 regulations required pressure testing to 125 percent in excess of the proposed MAOP.

[55] ''Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards,'' 35 FR 13248; August 19, 1970.

[56] 35 FR 13248.

[57] This requirement is currently under § 192.619(c).

[58] 35 FR 13248.

[59] ''Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans;'' California Public Utilities Commission Order; June 9, 2011.

[60] *https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages.*

threats to each covered pipeline segment; (3) include in its baseline assessment plan all potential threats on a covered segment and to select the most suitable assessment method; (4) prioritize high-risk pipeline segments for assessment where certain changed circumstances rendered the manufacturing threats on those segments unstable; and (5) prioritize pipeline segments containing low-frequency ERW pipe or other similar pipe as a high-risk segment for assessment if certain changed circumstances rendered a manufacturing seam threat on that segment unstable.

Congress required PHMSA, per the 2011 Pipeline Safety Act, to issue regulations to confirm the material strength of previously untested natural gas transmission pipelines located in HCAs and operating at a pressure greater than 30 percent of SMYS. Through this final rule, PHMSA is implementing that congressional directive and other safety measures. This final rule will improve the safety and public confidence of the Nation's onshore natural gas transmission pipeline system.

C. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an ANPRM to seek public comments regarding the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines. In the 2011 ANPRM, PHMSA requested comments on 122 questions spread through 15 broad topic areas covering both IM and non-IM requirements. Among the issues related to IM that PHMSA considered included whether the definition of an HCA should be revised and whether additional restrictions should be placed on the use of certain pipeline assessment methods. PHMSA also requested comment on non-IM regulations, including whether revised requirements are needed for mainline valve spacing and actuation, whether requirements for corrosion control should be strengthened, and whether new regulations are needed to govern the safety of gas gathering lines and underground natural gas storage facilities. Based on the comments received on several of the ANPRM topics, PHMSA developed proposals for some of those topics in a NPRM that is the basis for this final rule. That NPRM and the comments received, are discussed below. PHMSA did not find it appropriate to address all the topics in a single rulemaking. Those topics that were not discussed further in the NPRM for this final rule have been discussed or will be discussed in other rulemakings.

D. National Transportation Safety Board Recommendations

On August 30, 2011, following the issuance of the ANPRM, the NTSB adopted its report on the gas pipeline incident that occurred on September 9, 2010, in San Bruno, CA. On September 26, 2011, the NTSB issued safety recommendations P–11–8 through -20 to PHMSA. Several of the NTSB's recommendations related directly to the topics discussed in the 2011 ANPRM and 2016 NPRM, and they shaped the direction of this final rule. The NTSB recommendations addressed in this final rule include:

• Exemption of Facilities Installed Prior to the Regulations. NTSB Recommendation P–11–14: *Amend Title 49 Code of Federal Regulations 192.619 to repeal exemptions from pressure test requirements and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.*''

• Pipe Manufactured Using Longitudinal Weld Seams. NTSB Recommendation P–11–15: ''*Amend Title 49 Code of Federal Regulations Part 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure.*''

• Incorporating interstates, highways, etc., into the list of ''identified sites'' that establish a HCA. NTSB Recommendation P–14–1: ''*Revise Title 49 CFR Section 903, Subpart O, Gas Transmission Pipeline Integrity Management, to add principal arterial roadways including interstates, other freeways and expressways, and other principal arterial roadways as defined in the Federal Highway Administration's* ''*Highway Functional Classification Concepts, Criteria and Procedures*'' *to the list of* ''*identified sites*'' *that establish an HCA.*

• Increase the use of ILI tools. NTSB Recommendation P–15–20: ''*Identify all operational complications that limit the use of in-line inspection tools in piggable pipelines, develop methods to eliminate the operational complications, and require operators to use these methods to increase the use of in-line inspection tools.*''

E. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

The 2011 Pipeline Safety Act relates directly to the topics addressed in PHMSA's ANPRM of August 25, 2011, and the NPRM issued on April 8, 2016. The related topics and statutory citations include, but are not limited to:

• Section 5(e)—Allow periodic reassessments to be extended for an additional 6 months if the operator submits sufficient justification.

• Section 5(f)—Requires the expansion of IM system requirements, or elements thereof, beyond HCAs, if appropriate.

• Section 23—Requires the reporting of each exceedance of the MAOP that exceeds the build-up allowed for the operation of pressure-limiting or -control devices.

• Section 23—Requires testing to confirm the material strength of previously untested natural gas transmission pipelines and pipelines lacking records that accurately reflect the pipeline's physical and operational characteristics.

• Section 29—Requires consideration of seismicity when evaluating pipeline threats.

F. Notice of Proposed Rulemaking

On April 8, 2016, PHMSA published an NPRM seeking public comments on the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines and gas gathering pipelines (81 FR 20721).[61] When developing the NPRM, PHMSA considered the comments it received from the ANPRM and proposed new pipeline safety requirements and revisions of existing requirements in several major topic areas, including those topics addressing congressional mandates and related NTSB recommendations. A summary of the NPRM proposals and topics pertinent to this rulemaking, the comments received on those specific proposals, and PHMSA's response to the comments received is below under the ''Analysis of Comments and PHMSA Response'' section.

PHMSA determined it could more quickly move a rulemaking that focuses on the mandates from the 2011 Pipeline Safety Act by splitting out the other provisions contained in the NPRM into two other, separate rules. Promptly issuing a final rule focused on mandates will improve safety and respond to Congress, industry, and public safety groups.

[61] *https://www.regulations.gov/document?D=PHMSA-2011-0023-0118.*

As such, not all the topics from the NPRM nor the comments received on those topics are discussed as a part of this rulemaking. PHMSA intends to issue two additional final rules to address the remaining topics from the NPRM.

III. Analysis of NPRM Comments, GPAC Recommendations, and PHMSA Response

On April 8, 2016, PHMSA published an NPRM (81 FR 20722) proposing several amendments to 49 CFR part 192. The NPRM proposed amendments addressing topiic areas including verification of pipeline material properties, MAOP reconfirmation, IM clarifications, MAOP exceedance reports, ILI launcher and receiver safety, assessing areas outside of HCAs, and recordkeeping. The comment period for the NPRM ended on July 7, 2016. PHMSA received approximately 300 submissions containing thousands of comments on the NPRM. Submissions were received from groups representing the regulated pipeline industry; groups representing public interests, including environmental groups; State utility commissions and regulators; members of Congress; specific pipeline operators; and private citizens.

Some of the comments PHMSA received in response to the NPRM were comments beyond the scope or authority of the proposed regulations. The absence of amendments in this proceeding involving other pipeline safety issues (including several topics listed in the ANPRM) does not mean that PHMSA determined additional rules or amendments on those other issues are not needed. Such issues may be the subject of other existing rulemaking proceedings or future rulemaking proceedings.

The remaining comments reflect a wide variety of views on the merits of particular sections of the proposed regulations. PHMSA read and considered all the comments posted to the docket for this rulemaking.

The Technical Pipeline Safety Standards Committee, commonly known as the Gas Pipeline Advisory Committee (GPAC; the committee), is a statutorily mandated advisory committee that advises PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas pipelines.[62] The GPAC is one of two pipeline advisory committees that focus on technical safety standards that were established under the Federal Advisory Committee Act (Pub. L. 92–463, 5 U.S.C. App. 1–16) and section 60115 of the Federal Pipeline Safety Statutes (49 U.S.C. Chap. 601). Each committee consists of 15 members, with membership divided among Federal and State agencies, regulated industry, and the public. The committees consider the ''technical feasibility, reasonableness, cost-effectiveness, and practicability'' of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

Due to the size and technical detail of this rulemaking, the GPAC met five times to discuss this rulemaking throughout 2017 and 2018.[63] During those meetings, the GPAC considered the specific regulatory proposals of the NPRM and discussed various comments made on the NPRM's proposal by stakeholders, including the pipeline industry at large, public interest groups, and government entities. To assist the GPAC in its deliberations, PHMSA presented a description and summary of the major proposals in the NPRM and the comments received on those issues. PHMSA also assisted the committee by fostering discussion and developing recommendations by providing direction on which issues were most pressing.

For the proposals finalized in this rulemaking, the committee came to consensus when voting on the technical feasibility, reasonableness, cost-effectiveness, and practicability of the NPRM's provisions. In many instances, the committee recommended changes to certain proposals that the committee found would make certain proposals more feasible, reasonable, cost-effective, or practicable.

The substantive comments received on the NPRM as well as the GPAC's recommendations are organized by topic below and are discussed in the appropriate section with PHMSA's response and resolution to those comments.

A. Verification of Pipeline Material Properties and Attributes—§ 192.607

i.—Applicability

1. Summary of PHMSA's Proposal

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of the pipelines and to confirm the established MAOP of gas transmission pipelines. Since 2012, operators have submitted information indicating that a portion of transmission pipeline segments do not have adequate records to establish MAOP or that accurately reflect the physical and operational characteristics of the pipeline. Therefore, PHMSA determined that additional regulations are needed to implement this requirement of the 2011 Pipeline Safety Act. Specifically, PHMSA proposed that operators conduct tests and other actions needed to confirm and document the physical and operational characteristics for those pipeline segments where adequate records are not available, and PHMSA proposed standards for performing these actions. PHMSA sought to appropriately address pipeline risk without extending the requirement to all pipelines where risk and potential consequences are not as significant, such as pipelines in remote, sparsely-populated areas. As a result, PHMSA proposed criteria that would require material properties verification for higher-risk locations through a new § 192.607; specifically, by adding requirements for the verification of pipeline material properties for existing onshore, steel, gas transmission pipelines that are located in HCAs or Class 3 or Class 4 locations.

2. Summary of Public Comment

Several citizen and public safety groups, including Pipeline Safety Trust (PST), Pipeline Safety Coalition, National Association of Pipeline Safety Representatives (NAPSR), Coalition to Reroute Nexus, Earthworks, and The Michigan Coalition to Protect Public Rights-of-Way, supported the proposed provisions for establishing adequate material properties documentation and records. Some of these groups noted that the need for this section in the regulations would suggest poor operator implementation of the IM requirements since the inception of subpart O back in 2003.

Trade associations and pipeline industry entities were largely opposed to the material properties verification requirements for several reasons outlined below.

Many trade association and pipeline industry commenters expressed concern that the material properties verification requirements were potentially retroactive. American Petroleum Institute (API) and American Gas Association (AGA) asserted that this proposal would require operators to document and verify the material properties of existing pipelines beyond

[62] 49 U.S.C. 60115.

[63] Specifically, the GPAC met on January 11–12, 2017; June 6–7, 2017; December 14–15, 2017; March 2, 2018; and March 26–28, 2018. Information on these meetings can be found at *regulations.gov* under docket PHMSA–2011–0023 and at PHMSA's public meeting page: *https://primis.phmsa.dot.gov/meetings/*.

what was required by the regulations that were in place at the time those pipelines were put into service. These commenters stated that this retroactive requirement extends beyond the congressional authority provided to PHMSA. Several commenters, including AGL Resources, Dominion East Ohio, and New Jersey Natural Gas, expressed concern with the proposed provisions for verifying specific physical characteristics of pipelines, fittings, valves, flanges, and components for existing transmission pipelines. These stakeholders stated that it might be impossible to achieve ''reliable, traceable, verifiable, and complete'' records on a retroactive basis for existing pipelines. Some commenters, including AGA, stated that a pipeline's MAOP should be considered confirmed and there should be no need to further document material properties to verify the MAOP if operators had a pressure test record of a test conducted at 1.25 times MAOP for the pipeline segment.

Commenters also expressed concern about PHMSA's proposed new references to the material properties verification requirements under § 192.607 throughout part 192, which could be interpreted as being applicable not only to a subset of transmission pipelines but also to distribution pipelines. Commenters stated that PHMSA did not provide justification within the NPRM for applying material properties verification requirements to distribution systems, and such requirements would significantly impact distribution systems. These commenters requested that PHMSA explicitly exclude distribution pipelines from the proposed material properties verification requirements. Similarly, some commenters urged PHMSA to restrict these requirements only to gas transmission lines operating at greater than 30 percent SMYS based on the premise that lines operating below 30 percent SMYS, in most cases, tend to leak before rupture and are therefore less risky to the public. Additionally, commenters suggested that PHMSA review the various cross-references in the NPRM and eliminate those that would expand the applicability of the material properties verification requirements beyond onshore steel gas transmission pipelines in HCAs and Class 3 and Class 4 locations.

Some commenters recommended changing the size limit for small components that might trigger the material properties verification requirements from greater-than-or-equal-to 2 inches to greater-than 2 inches. A further comment on components discussed how the material properties verification provisions, as proposed, require the operator to know the weld-end bevel conditions for in-service valves and flanges. Operators noted, however, that once a weld-end is welded to a piece of pipe or other component, there is no method that can be employed to determine the condition of that bevel. Accordingly, the commenters requested this requirement be deleted or clarified. There was also a comment to delete the sampling requirement and not perform material properties verification if, when the applicable pipeline is excavated for repairs, a repair sleeve is installed. Other commenters felt that the proposed material properties verification requirements would not deliver clear, identifiable safety benefits and would lead to several unintended consequences that would decrease the integrity of pipeline systems and cause energy supply disruption. Accordingly, these commenters suggested PHMSA withdraw the proposed requirements for material properties verification.

Multiple commenters also expressed concerns that the revised provisions for establishing MAOP under § 192.619, specifically the requirement for operators to maintain all records necessary to establish and document a pipeline's MAOP as long as the pipeline remains in service, would impose extensive new recordkeeping requirements applicable to operators of distribution pipelines, including retroactive recordkeeping requirements. Commenters requested that PHMSA clarify that the new recordkeeping requirements in § 192.619(f) are applicable only to gas transmission pipelines.

Pipeline industry entities also provided comments on the relationship of the material properties verification requirements in § 192.607 and the MAOP reconfirmation requirements in § 192.624. The Gas Piping Technology Committee (GPTC) suggested that the proposed material properties verification requirements be revised to include an option of using the provisions of § 192.619(a)(1) for establishing MAOP when traceable, verifiable, and complete material property records are not available for calculating design pressure. Similarly, commenters suggested operators should be allowed to establish design yield strengths for unknown pipe grade as described at § 192.107(b)(1). Xcel Energy also stated that if an operator has previously established MAOP as per the § 192.619(a)(2) strength test requirements or will do so per the proposed § 192.624 methodology for pressure test or pressure reduction, the verification of pipeline material proposed in § 192.607 is not necessary for the purpose of ensuring safe operation.

Over the course of the meetings on June 7, 2017, and December 14, 2017, the GPAC had a robust discussion regarding the applicability of the material properties verification requirements. More specifically, the GPAC discussed the fact that two separate activities drive the need for material properties verification: (1) MAOP reconfirmation for pipelines lacking traceable, verifiable, and complete records to support the pipeline's current MAOP; and (2) the application of IM principles, especially where anomaly response and remediation calculations are concerned. The GPAC believed these aspects needed to be addressed separately in the final rule.

Subsequently, on December 14, 2017, the GPAC recommended that PHMSA modify the proposed rule by removing the applicability criteria of the material properties verification requirements and make material properties verification a procedure for obtaining missing or inadequate records or otherwise verifying pipeline attributes if and when required by MAOP reconfirmation requirements or by other code sections. In discussing the issue, the GPAC recognized that the broad applicability of the material properties verification requirements in the proposed rule was PHMSA's attempt to address the issue of inadequate records for MAOP verification, IM requirements and standard pipeline operations. The GPAC believed amending the proposed rule to remove the proposed applicability and instead explicitly refer back to the material properties verification requirements, when needed, in various regulatory sections, would more closely follow Congress' direction in the 2011 Pipeline Safety Act.

This change would also obviate the need for operators to create a material properties verification program plan per the originally proposed requirements, so the GPAC recommended PHMSA remove that requirement from the rule. Further, the committee recommended during a later meeting that PHMSA consider modifying the rule in both §§ 192.607 and 192.619 to clarify that the material properties verification requirements apply to onshore steel gas transmission lines and not to distribution or gathering pipelines.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the scope and requirements for reconfirming the material properties of pipelines with unknown or undocumented properties. PHMSA agrees that the need for this rule is caused, in part, by poor implementation of existing IM requirements. However, PHMSA disagrees that the requirements would not deliver safety benefits or would lead to decreased integrity of pipeline systems and cause energy supply disruption. The basic knowledge of pipeline material properties is essential to pipeline safety.

PHMSA disagrees that material properties verification is not needed if the pipeline segment has been pressure tested to 1.25 times MAOP. Other reasons for needing documented, confirmed material properties (*e.g.,* wall thickness, yield strength, and seam type) include IM program requirements, implementation of pipe repair criteria and determination of the design pressure of the pipeline segment. This rule supplements existing IM requirements by providing operators a method to reconfirm material properties without necessarily performing destructive testing of the pipe material. Operators can use this method in their IM programs, to reconfirm MAOP where needed, to implement repair requirements, and to otherwise comply with part 192 where necessary. Indeed, PHMSA hopes that operators will use this method for material properties verification even when not specifically required by part 192 because it provides a common-sense, opportunistic, and practical approach for gathering the records necessary to substantiate safe MAOPs, properly implement IM, and otherwise ensure the safe operation of the nation's pipeline network.

PHMSA also disagrees that material properties verification is only needed for pipeline segments operating at pressure greater than 30 percent of SMYS. IM requirements apply to all gas transmission pipeline segments in HCAs, including those that operate at less than 30 percent of SMYS. Moreover, the gas transmission subpart O integrity management regulations at § 192.917(b), *Data gathering and integration,* require operators to gather pipe attributes including pipe wall thickness, diameter, seam type and joint factor, manufacturer, manufacturing date, and material properties. These physical properties and attributes are explicitly outlined in ASME/ANSI B31.8S—2004 Edition, section 4, table 1—Data Elements for Prescriptive Pipeline Integrity Program, which is incorporated by reference in § 192.7.

PHMSA did not intend that the requirements proposed in § 192.607 would be retroactive or would apply to distribution or gathering lines. Therefore, PHMSA is clarifying the final rule to assure that the provisions finalized in § 192.607 are not retroactive [64] and apply only to transmission lines. However, PHMSA believes that operators with IM programs that are properly following subpart O, specifically § 192.917(b), should already have this pipe information.

Regarding material properties verification for non-line pipe components, PHMSA is revising this final rule to apply the requirements to components greater than 2 inches and is removing the requirement to know the weld-end bevel conditions. PHMSA agrees with the GPAC members who commented that 2-inch pipe is not used in mainline applications and need not be subject to additional regulatory requirements to maintain safety. Also, fittings and flanges will have an ANSI class rating that will confirm whether the components meet or exceed the MAOP of the pipeline, so further regulatory requirements for components under 2 inches are not necessary to maintain safety.

To further address comments and the GPAC recommendations related to the scope and applicability of the material properties verification requirements, PHMSA is modifying this final rule to address MAOP reconfirmation and material properties verification separately from the application of IM principles. PHMSA believes this change will improve the organization of the rule. PHMSA is accomplishing this by removing the applicability criteria of the material properties verification requirements and making material properties verification a procedure for obtaining records for physical pipeline properties and attributes that are not documented in traceable, verifiable, and complete records or otherwise verifying physical pipeline properties and attributes when required by MAOP reconfirmation requirements, IM requirements, repair requirements, or other code sections. This obviates the need for all operators to create a material properties verification program plan per the originally proposed requirements, so PHMSA is removing that requirement from the rule as well. Instead, only operators who do not have traceable, verifiable, and complete records will be required to create such a plan.

A. Verification of Pipeline Material Properties and Attributes—§ 192.607

ii.—Method

1. Summary of PHMSA's Proposal

The conventional method for determining the properties of unknown steel pipe material is to cut test specimens known as ''coupons'' out of the pipe and perform destructive testing. Because of the large amount of pipe operators reported in Annual Report submissions for which there are unknown or inadequately documented properties, the cost of such a conventional approach would likely be onerous. Therefore, PHMSA proposed standards in § 192.607 by which operators could develop a material properties verification plan and use an opportunistic sampling technique to re-constitute and document material properties in a more cost-effective manner. More specifically, PHMSA proposed to allow operators to use recently developed technology to perform *in situ,* non-destructive examinations for determining the properties of unknown steel pipe material.

While PHMSA acknowledged in the preamble of the NPRM that such techniques may not be possible in every situation, PHMSA stated that it was aware that this option is already being widely deployed in the pipeline industry. Secondly, PHMSA proposed to allow operators to determine pipe properties at a sampling of similar locations and apply those results to the entire population of pipeline segments. PHMSA proposed to allow operators to take advantage of opportunities when the pipeline is exposed for other reasons, such as during maintenance and repair excavations, by requiring that material properties be verified whenever the pipe is exposed. This would reduce the number of excavations that might otherwise be required. Excavations are a large portion of the cost of re-constituting material properties for unknown pipe.

2. Summary of Public Comment

Several commenters suggested that the data required by the material properties verification process proposed by PHMSA can be obtained only through destructive pipe testing. These commenters asserted that the proposed requirements would lead to unnecessary service outages, increased methane emissions, and increased personnel

[64] The material properties verification requirements are not retroactive as they mandate the creation and retention of records as operators execute the methodology in § 192.607 on a prospective basis. Operators who have not verified their records in accordance with this methodology before the effective date of this rule will not be subject to enforcement action based on § 192.607. After the effective date of the rule, operators with missing or inadequate records must follow the verification methodology in § 192.607.

safety risks due to unnecessary excavation activities. Black Hills Energy stated that their pipeline system consists of mainly smaller-diameter transmission pipelines and that the proposed provisions would force them to take lines out of service to perform costly cutouts. API asserted that the expense and risk required for the excavations necessary to comply with the proposed provisions outweigh the value of obtaining and documenting material pipe properties. Some commenters suggested that it would be less costly for operators to simply replace pipe rather than obtain the material properties for pipe already in the ground. A commenter asserted that the proposed requirements would require unnecessary breaching of the pipeline coating, which is important for effective cathodic protection. API suggested that rather than requiring operators to gather documentation on material properties that may only be of marginal value for assessing pipeline safety, PHMSA should require a combination of hydrostatic pressure testing and ILI. API stated that, as opposed to the proposed rule's focus on the precise documentation of materials, this would appropriately shift the emphasis of the proposed regulations to confirming MAOP and away from material properties verification.

Several commenters stated that some of the data that PHMSA proposed operators verify is unnecessary for MAOP reconfirmation or other operational reasons. For example, the Interstate Natural Gas Association of America (INGAA) stated that several of the data elements that would need to be verified pursuant to the proposed material properties verification requirements are unnecessary for integrity management-related activities. Commenters suggested that PHMSA limit the required records to what is needed to calculate design pressure in order to determine MAOP. Commenters noted that the proposed requirements would require testing for stress corrosion cracking (SCC) in all cases, and that the requirement should be limited to only pipelines that are susceptible to SCC. Some commenters disagreed with the requirement to determine and keep a record for the chemical composition of steel transmission pipeline segments installed prior to the effective date of the final rule, suggesting that this information has not been previously required. Another commenter stated that the basis for having accurate chemical composition records is unclear. PG&E recommended that PHMSA recognize that chemical composition and manufacturing specifications provide limited information that can be used to evaluate the safety of an existing pipeline system. Piedmont Natural Gas stated that any requirement to retroactively obtain ultimate tensile strength and chemical composition is unnecessarily burdensome and detracts from the ultimate goal of pipeline safety by diverting valuable resources away from other risk-reduction efforts. A similar comment asserted there was no benefit in determining pipeline chemical compositions, as there is a high probability that many pipelines that might otherwise have adequate material documentation would fail the recordkeeping requirements because of a lack of existing chemical composition records and would subsequently be subject to the entire material properties verification process.

Pipeline industry entities also commented on the proposed sampling and testing requirements that would occur during excavations. Commenters asserted that the sampling requirements should be removed, and the number of excavations should not be specified. One commenter stated that the minimum number of excavations should be determined by the operator in their material properties verification plan and through statistical analysis aimed at achieving targeted confidence levels. Texas Pipeline Association (TPA) stated that there is no technical justification for the number of material properties tests being required at each test location by the proposed rule, and that the requirement of five tests in each circumferential quadrant for non-destructive tests and one test in each circumferential quadrant for destructive tests is unsupported in the proposal. TPA further stated that they are unaware of any indication that there is great variability in material properties within the body of a pipe, and that presently, material properties verification involves a single test per cylinder. Additionally, commenters stated this requirement could be unnecessarily costly and have a negative impact on pipeline safety, as the integrity of the pipeline would need to be compromised to perform these evaluations and a new joint of pipe would need to be welded onto the existing pipeline. Lastly, Spectra Energy Partners objected to the requirement that non-destructive testing be validated with unity plots comparing the results from non-destructive and destructive testing. They stated that this severely limits the value of non-destructive testing since the operator will have to remove samples for destructive testing to create the unity plots.

CenterPoint Energy stated that the definition of excavation is unclear, and that pipe may be excavated to a point for many operational activities, including spotting for construction safety and installing cathodic protection tests or current source wires. CenterPoint Energy stated that they do not view these types of excavations as opportunities for material properties verification data gathering because that would require the full exposure of a pipeline segment and the removal of good coating from the pipe. Another commenter suggested that confidence specifications for non-destructive testing would add significant cost due to inherently inaccurate test results.

Similarly, there were comments that encouraged consistency between the material properties verification requirements and the requirements for recordkeeping for materials, pipe design, and pipeline components. These comments suggested that inconsistencies between the documentation and the recordkeeping requirements could create scenarios where operators meet the recordkeeping requirements but do not have adequate documentation to prevent the material properties verification requirements from triggering.

Some commenters opposed the proposed requirement to obtain a ''no objection'' letter from PHMSA in order to use a new or other technology. PG&E recommended that PHMSA provide additional regulatory language to allow an operator to proceed with the new technology if a ''no objection letter'' to PHMSA is not received within 45 days prior to the planned use of technology. They stated that operators put in considerable time to set up contracts, schedule work, acquire permits, and that waiting on an approval or disapproval from PHMSA can dramatically impact schedule and costs. Further, commenters suggested that PHMSA's enforcement and regulatory procedures do not provide for ''no objection'' letters, and adding a new process that is not well-defined could cause additional confusion.

AGA proposed an alternative approach to material properties verification, MAOP reconfirmation, and integrity assessments outside of HCAs, which other pipeline industry entities supported. The approach included requiring operators to either pressure test or utilize an alternative technology that is determined to be of equal effectiveness on high-risk gas transmission pipelines that do not have a record of a subpart J pressure test or are currently utilizing the grandfather clause for MAOP determination (§ 192.619(c)). AGA suggested a three-tiered approach that prioritized pipelines located in HCAs and operating at pressures greater than 30 percent SMYS. The approach also included the use of ILI tools on all gas transmission pipelines that are able to accommodate inspection by means of an instrumented ILI tool. The ILI tool used would be qualified to find defects that would fail a subpart J pressure test. Commenters stated that this alternative approach is simpler and would allow operators to focus resources on the areas of highest risk within pipeline systems. In conjunction with AGA's approach, commenters recommended including language that would allow the use of advanced ILI and non-destructive evaluations to comply with the proposed material properties verification requirements.

Certain commenters also suggested PHMSA provide a deadline by which operators must implement their material properties verification plan, as it was unclear in the proposal. Following committee discussion and PHMSA feedback, industry groups also recommended to allow operators to use their own statistical sampling plans when undertaking material properties verification rather than have PHMSA specify the number of samples that must be obtained.

At the GPAC meeting on December 14, 2017, the committee recommended that PHMSA modify the method for material properties verification by clarifying that operators are only required to confirm attributes pertinent to the goal of MAOP reconfirmation, integrity management, or other reasons when the material properties verification is being performed. The GPAC also recommended that PHMSA require operators keep records developed using the material properties verification method. The GPAC recommended that PHMSA retain the opportunistic approach of obtaining unknown or undocumented material properties when excavations are performed for repairs or other reasons, using a one-per-mile standard proposed by PHMSA, but allow operators to propose an alternative statistical approach and submit a notification to PHMSA with justification for their method. The GPAC also recommended that if operators notify PHMSA of an alternative sampling approach, and the operator does not receive an objection letter from PHMSA within 90 days of such a notification, the operator can proceed with their chosen method unless PHMSA notifies the operator that additional review time or additional information from the operator is needed for PHMSA to complete its review.

Similarly, the committee recommended PHMSA delete specified program requirements for how to address sampling failures and replace that with a requirement for operators to determine how to deal with sample failures through an expanded sample program that is specific to their system and circumstances. They further recommended that PHMSA require operators to notify PHMSA of the expanded sample program and establish a minimum standard that sampling programs must be based on a minimum 95 percent confidence level.

Further, the committee recommended that PHMSA retain the flexibility for operators to conduct either destructive or non-destructive tests when material properties verification is needed and requested PHMSA drop accuracy specifications but retain the requirement that any test methods used be validated and be performed with calibrated equipment. The GPAC also recommended PHMSA reduce the number of quadrants at which non-destructive evaluation tests be made from four to two.

Regarding the number of test locations and the number of excavations that must be performed, the GPAC recommended PHMSA accommodate situations where a single material properties verification test is needed (*e.g.,* additional information is needed for an anomaly evaluation/repair) and drop the mandatory requirements for testing multiple joints for large excavations. The GPAC also recommended PHMSA clarify the applicability of the requirements for developing and implementing procedures for conducting material properties verification tests on populations of undocumented or inadequately documented pipeline segments and the minimum number of excavations and tests that must be performed for those pipeline segments.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the method for material properties verification. PHMSA disagrees with implementing the alternative approach proposed by AGA, but the underlying comments of AGA and others related to having an alternative approach are discussed in this rulemaking and are addressed below. PHMSA strongly believes that knowledge of pipeline physical properties and attributes are essential for a modern IM program (see § 192.917(b)—*Data gathering and integration*) as well as effective pipeline and public safety. The PG&E incident at San Bruno, CA, was caused, in part, by PG&E mistakenly classifying the pipe that failed as seamless pipe. That pipe was welded seam pipe, and the failure occurred at a partially welded seam.

The NPRM included a list of material properties that could be confirmed using the material properties verification process. One of them in particular, steel toughness, is conventionally obtained only through destructive testing. It was not PHMSA's intent that toughness would need to be confirmed every time an operator was performing material properties verification, thus in effect requiring destructive testing for every location. Therefore, PHMSA is modifying this final rule to address toughness properties in a separate paragraph and is allowing the use of techniques that are reliable without specifying destructive testing. This is intended to accommodate new, non-destructive techniques currently under development. The new paragraph with these requirements also makes it clear that toughness is required only where needed and not necessarily in every case. PHMSA is also modifying other sections of this final rule to provide reasonably conservative default toughness values so that operators may achieve the goals of IM and MAOP reconfirmation using assumed values without the need for destructive testing. These changes will be discussed further in subsequent sections of this document.

Similarly, PHMSA is modifying the verbiage related to the listing of material properties to which the material properties verification process would apply. The clarification will make it clear that the material properties verification process only applies to the pertinent properties needed to achieve the goals of the activity for which material properties verification is needed, such as MAOP reconfirmation or IM. This avoids the potential for requiring that all properties be documented each time an operator goes out to perform material properties verification when only a subset of properties is needed.

PHMSA is also replacing the prescriptive accuracy specifications and unity plot validation for non-destructive testing with more general verbiage that requires that methods are validated and that operators account for the accuracy of the method used. This change will help accommodate new technology and techniques currently under development and avoid situations that might require destructive testing to validate the non-destructive methods.

In response to the comments, PHMSA is relaxing the number of test points for non-destructive tests from four quadrants to two quadrants. This allows the operator to perform material properties verification on the top half of the pipe and would avoid the need to access the bottom half of the pipe when the repair or maintenance activity would not otherwise require it. PHMSA is also removing the proposed requirement to conduct material verification at multiple locations within a single large excavation based on the number of joints of line pipe exposed. PHMSA believes the methods described in this final rule will provide operators accurate material properties information without requiring more excavation activities than necessary.

In this final rule, PHMSA is modifying § 192.607 to specifically list the types of excavations where operators that need to verify material properties should seek to conduct material properties verification. This revision intends to avoid requiring operators perform the material properties verification process at partial excavations that do not expose the pipeline segment. For example, PHMSA considers excavations associated with direct examinations of anomalies to be an opportunity to perform material properties verification. Similarly, PHMSA is modifying the language to acknowledge the need to perform one-time material properties verification activities at specific locations, such as when performing repairs. An operator who has complete material documentation for a particular pipeline segment would not need to undertake the sampling program at excavations on that particular segment. The sampling program is specifically required when the operator needs to document material properties for entire segments of pipelines.

PHMSA disagrees with the removal of the number of samples needed and is maintaining the minimum standard to define the number of excavations in the sampling program as 1 per mile or 150 if the population of pipeline segments is more than 150 miles, whichever is less. However, PHMSA is modifying the rule to provide operators the option of proposing an alternative sampling program if they send a notification and justification of the alternative program to PHMSA in accordance with the new notification procedures at § 192.18. Operators may use an alternative sampling program 91 days after submitting a notification per § 192.18 to PHMSA if the operator has not received a letter of objection or a request from PHMSA for more time to review.

PHMSA is also withdrawing the expanded sampling requirements to address cases where operators identify problems in the initial sampling program. Instead, operators may use an alternative sampling approach that addresses how the operator's sampling plan will address findings that reveal physical pipeline properties and attributes that are not consistent with all available information or existing expectations or assumed physical pipeline properties and attributes used for pipeline operations and maintenance in the past. Operators taking such an approach must notify PHMSA of the adverse findings and provide PHMSA with specific details of the alternative sampling plan with a justification for such a plan in a notification to PHMSA. The alternative sampling program must be designed to achieve a 95 percent confidence level. In accordance with the new notification procedures at § 192.18, operators may use an alternative sampling plan 91 days after submitting a notification to PHMSA if the operator has not received a letter of objection or a request from PHMSA for more time to review.

In response to committee discussion, PHMSA is modifying its notification process broadly throughout part 192 to allow operators to propose using methods and technologies by notifying PHMSA in accordance with the new procedures in § 192.18. If an operator does not receive a letter of objection or a request from PHMSA for more time to review within 90 days of the notification, then the operator may use the proposed method or technology. Some committee members were concerned that some provisions throughout the NPRM would require action from PHMSA in the form of a ''no objection'' letter. Members noted that such a process can leave companies unable to proceed until PHMSA provided affirmative approval of the request. Committee members suggested that it may be more efficient and less burdensome for PHMSA to issue letters to operators only when they specifically object to proposed plans or solutions, and otherwise allow the operator to proceed as planned in the absence of such a letter. Other members were concerned that PHMSA might authorize sub-optimal plans or technologies by missing a deadline. To this end, members recommended an approach where PHMSA could request additional time for review beyond the 90-day period. PHMSA noted at the meeting that this is a similar process that is used by PHMSA for state waivers and the change should improve regulatory efficiency.

PHMSA's letter or email of objection will specify the reasons PHMSA does not approve of the proposed method or technology, while a request from PHMSA for more time to review the notification will extend the review period beyond 90 days. Further, to establish a verifiable record, it will be PHMSA's policy to send a ''no objection'' letter or email, either before or after the 90-day review period, when PHMSA does not object to an operator's proposed method or technology. PHMSA is applying this approach to other places in this rulemaking that require notifications and has created a general notification provision in subpart A of part 192.

PHMSA is modifying the recordkeeping requirement for the material properties verification provisions to avoid potential conflicts with other provisions in this rulemaking, such as MAOP reconfirmation, to clarify that operators are required to keep any records created, for the life of the pipeline, when verifying specific properties using the methods in § 192.607. These records must also be traceable, verifiable, and complete. These recordkeeping requirements are not retroactive, as they mandate the creation and retention of records as operators execute the methodology in § 192.607 on a prospective basis.

PHMSA disagrees with commenters that asked for PHMSA to establish a deadline for operators to complete the sampling programs. The opportunistic approach PHMSA proposed and retained for this final rule requires material properties verification activities to occur at excavation sites where operators are directly examining anomalies; performing *in-situ* evaluations; or are performing repairs, remediation, or maintenance. PHMSA does not expect operators to perform material properties verification for unknown pipe properties on pipeline segments exposed during one-call excavations. PHMSA has determined this approach is reasonable and will minimize the cost impacts of this final rule. A deadline for the material properties verification requirements of this rulemaking is not practical because it is impossible to forecast the rate or timing at which opportunities would arise to perform material properties verification for a given population of pipe.

Lastly, operators should have most of the required pipe information from following § 192.917(b) since subpart O of part 192 was codified over 15 years ago in 2003. Section 192.917(b) requires operators to identify and evaluate the potential threats to pipeline segments by gathering and integrating existing data and information on the entire pipeline that could be relevant to the pipeline segment. In performing this identification and evaluation, operators must follow the requirements in ASME/ANSI B31.8S, section 4, and at a minimum gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S. The material properties needed to establish and substantiate MAOP are included in these lists.

B. MAOP Reconfirmation—§§ 192.624 & 192.632

i.—Applicability

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to require operators reconfirm MAOP for the following three categories of pipeline:

(1) Grandfathered pipe, in direct response to section 23(d) of the 2011 Pipeline Safety Act and NTSB recommendation P–11–14;

(2) Pipe for which documentation is inadequate to support the MAOP, in direct response to section 23(c) of the 2011 Pipeline Safety Act; and

(3) Pipe that has experienced a reportable in-service incident since its most recent successful subpart J pressure test due to an original manufacturing-related defect; a construction-, installation-, or fabrication-related defect; or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spots, or stress corrosion cracking.

It is important to note that a given pipeline segment for which the MAOP reconfirmation process would apply might fit into one, two, or all three of these proposed categories. For pipeline segments where records of the pipeline physical properties and attributes to substantiate the current MAOP are not documented in traceable, verifiable, and complete records, only those segments located within an HCA or a Class 3 or Class 4 location would be subject to the MAOP reconfirmation process under the NPRM.

This proposal directly correlates to section 23 of the 2011 Pipeline Safety Act and NTSB recommendation P–11–14 regarding the need for spike hydrostatic testing where in-service incidents have occurred. The NTSB recommended such testing for all pipe manufactured before 1970.

For pipeline segments where operators established the MAOP in accordance with the grandfather clause at § 192.619(c) (*i.e.,* pipeline segments where the MAOP is based upon the highest actual operating pressure records from a 5-year interval between July 1, 1965, to July 1, 1970, and where operators therefore do not have pressure test or material property records) or for segments with a history of in-service incidents caused by cracks or crack-like defects, PHMSA proposed to restrict the applicability of MAOP reconfirmation to HCAs, Class 3 or Class 4 locations, or MCAs, if the MCA segment can accommodate an ILI tool. The proposed inclusion of pipeline segments in these locations and with these traits slightly expand on the mandate contained in section 23 of the 2011 Pipeline Safety Act, which applied only to previously untested pipeline segments operating at a pressure greater than 30 percent SMYS located in an HCA.

In recommendation P–11–14, the NTSB recommended that all pipe manufactured before 1970 be subjected to a hydrostatic pressure test that would include a spike hydrostatic test, which PHMSA considered in its process for reconfirming MAOP. PHMSA's preliminary evaluation concluded that doing so may not be cost-effective, since a large amount of such pipe could be in remote locations where the likelihood of personal injury or property damage as a result of an incident would be low.

PHMSA's proposal expanded the applicability of MAOP reconfirmation beyond the minimum required by the congressional mandate to include pipe operating at less than 30 percent SMYS. In addition, the NPRM expanded the location criteria to include some non-HCA locations in the form of MCAs and Class 3 and Class 4 locations. As PHMSA proposed in the definitions section of the NPRM, MCAs are areas that, while not meeting the HCA criteria, include 5 or more persons or dwellings intended for human occupation or are otherwise locations where people congregate, including the right-of-ways of major roadways. See section H of this final rule for additional background on the MCA definition. The NPRM also specified that the MAOP reconfirmation process would apply only to MCA pipeline segments able to accommodate an ILI tool. This provision would not preclude an operator from choosing to conduct a pressure test, but it would avoid forcing operators to conduct a pressure test because the pipeline segment was not ''piggable.''

2. Summary of Public Comment

Many stakeholders provided input on the proposed provisions in § 192.624 that require MAOP reconfirmation for pipeline segments previously excluded from testing by the grandfather clause, pipeline segments without adequate documentation to substantiate the current MAOP, and pipeline segments that have experienced a reportable in-service incident.

Regarding the first criterion above, several commenters, including INGAA, AGA, and NAPSR, generally supported the provision requiring operators of pipeline segments where the MAOP was established via the grandfather clause to reconfirm the MAOP of those segments. Several of the pipeline industry trade associations and industry entities, however, did not support the proposed application of these criteria to all grandfathered pipeline segments within HCAs, Class 3 and Class 4 locations, and Class 1 and Class 2 piggable segments within MCAs. Gas Processors Association's Midstream Association (GPA) and AGA stated that while they support the congressional mandate to conduct testing to confirm the material strength of previously untested gas transmission pipelines in HCAs that operate at a pressure above 30 percent SMYS, they oppose the proposed provisions which extend to additional pipeline segments. INGAA and Washington Gas supported the applicability of MAOP reconfirmation in MCAs for pipelines operating at greater than or equal to 30 percent SMYS but disagreed with the proposed provisions that included MCA pipelines operating at less than 30 percent SMYS.

Some citizen groups, including PST, expressed concern that the proposed changes regarding the grandfather clause did not go far enough and suggested that PHMSA should fully implement the recommendations set forth by the NTSB. They stated that PHMSA should eliminate the grandfather clause given that the proposed provisions would not include the following groups of pipelines: (1) Pipelines in non-HCA areas within Class 1 and Class 2 locations; and (2) pipeline segments for which there is an inadequate record of a hydrostatic pressure test in areas newly designated as an MCA that are not capable of being assessed by an in-line tool. Conversely, Northeast Gas Association (NGA) stated that PHMSA should retain the grandfather clause as it prevents existing, historically safe, and maintained pipelines from being subjected to unwarranted requirements.

For pipeline segments where operators do not have adequate documentation to support the current MAOP and that PHMSA proposed would be subject to the new MAOP reconfirmation requirements, some commenters stated that they support the requirement to the extent that it is consistent with the congressional mandate to reconfirm MAOP for pipeline segments with insufficient records within Class 3 and Class 4 locations and Class 1 and Class 2 HCAs. These commenters further stated that § 192.624(a)(2) within the proposed MAOP reconfirmation requirements should be revised to clarify that it applies only to those gas transmission pipeline segments in HCAs and Class 3 and Class 4 locations that were constructed and put into operation since the adoption of the Federal Pipeline Safety Regulations in 1970, stating that otherwise § 192.624(a)(2) would apply to those pipelines put into service prior to the implementation of Federal regulations where the requirement to maintain a pressure test record does not apply. Some commenters also stated that PHMSA should revise § 192.624(a) within the proposed MAOP reconfirmation requirements to make clear that operators that have used one of the proposed allowable methods for establishing MAOP in § 192.624(b) other than the pressure test method are not required to have a pressure test record to comply with the record requirements of the section. Washington Gas asserted that the MAOP reconfirmation requirements should apply to only pipeline segments in HCAs that operate at a pressure of greater than or equal to 30 percent SMYS. Other commenters, including Xcel Energy, stated that the proposed provisions should allow operator discretion regarding what constitutes a reliable, traceable, verifiable, and complete record to determine the necessary documentation to support a pressure test record and the necessary material properties for MAOP verification. Additionally, AGA recommended the deletion of the phrase ''reliable, traceable, verifiable, and complete'' from the proposed MAOP reconfirmation provisions in § 192.624(a)(2). Similarly, other commenters, including INGAA, recommended omitting ''reliable'' from the phrase and provided a suggested definition for ''traceable, verifiable, and complete.''

Lastly, with regard to the third category of applicable pipeline segments to the proposed MAOP reconfirmation requirements, many commenters either disagreed or requested clarification for the requirement that MAOP must be reconfirmed in cases where an in-service incident occurred due to a manufacturing defect listed under § 192.624(a)(1). For example, INGAA stated that an operator can evaluate such manufacturing defects more effectively through ongoing operations and maintenance activities rather than through MAOP reconfirmation, and that the defects PHMSA is concerned with are already addressed through integrity management. Similarly, Boardwalk Pipeline stated that pipelines that have experienced an in-service incident because of the listed defects in § 192.624(a)(1) should be subject to integrity management measures rather than MAOP reconfirmation. TransCanada and TPA recommended adding text to the applicability section of the MAOP reconfirmation requirements that would exclude a pipeline segment from such requirements if the operator has already acted to address the cause of the reported incident. Additionally, one commenter suggested that this requirement should apply only to pipelines in HCAs. Some commenters, including AGA and Consolidated Edison of New York (Con Ed), also requested additional time to comply with the proposed MAOP reconfirmation provisions, asserting that operators would be required to replace many of their transmission mains to comply with the new requirements because their current records would not be satisfactory. Due to the urban density and scale of the service areas of certain operators, AGA and Con Ed stated that this replacement process would take longer than the 15-year schedule provided in the rule. One commenter suggested that if the applicability criteria for pipeline segments with in-service incidents and manufacturing defects remains in the rule, it should be limited to a more contemporary time frame, such as a rolling 15-year window or those in-service incidents that have occurred since 2003. Pipeline Safety Trust, on the other hand, stated that the proposed timeframe of 15 years is too long for operators to reconfirm MAOP in HCAs and complete critical safety work, and they urged PHMSA to adopt significantly shorter timelines in the final rule.

Additionally, AGA asserted that the proposed MAOP provisions do not address how the completion plan and completion dates of the section would apply to pipelines that might experience a failure in the future and would then be subject to the proposed MAOP reconfirmation requirements, or for pipelines that are not currently located in a MCA but may be in the future. Lastly, INGAA stated that section 23 of the 2011 Pipeline Safety Act requires that PHMSA consult with the Chairman of the Federal Energy Regulatory Commission (FERC) and State regulators before establishing timeframes for the testing of previously untested pipes, and it is not evident that PHMSA has complied with this requirement.

As a general comment, several stakeholders, including AGA, Louisville Gas & Electric, New Mexico Gas Company, National Grid, NW Natural, PECO Energy, TECO Pipeline Gas, and New York State Electric and Gas (NYSEG), proposed an alternative method for MAOP reconfirmation where operators would execute two separate sets of actions that they stated could be performed simultaneously or separately. First, operators would either assess high-risk gas transmission pipelines using a pressure test or an alternative technology that is determined to be of equal effectiveness. Operators would categorize these pipelines in three tiers and schedule them for testing depending on the pipeline's SMYS and class location. Second, operators would use an ILI tool on all gas transmission pipelines, regardless of class location, that are capable of accommodating ILI tools. The ILI tool used would be qualified to find defects that would fail a subpart J pressure test. These commenters stated that this alternative methodology was necessary because the proposed provisions would create operational inefficiencies that would likely result in excessive cost and limited public benefit. In addition to providing this alternative proposal, many of these commenters provided other assorted comments on the proposed provisions.

At the GPAC meeting on March 26, 2018, the GPAC recommended that PHMSA revise the scope of the proposed MAOP reconfirmation provisions by excluding lines with previously reported incidents due to crack defects. To go along with this, the GPAC also recommended PHMSA create a new section in subpart O of part 192, the natural gas IM regulations, to address pipeline segments with crack-related incident histories. Doing these actions would eliminate the need for the proposed definitions of ''modern pipe,'' ''legacy pipe,'' and ''legacy construction techniques,'' and the impact of this is discussed later in this document.

The GPAC also recommended that the MAOP reconfirmation provisions be revised to apply to pipeline segments in HCAs or Class 3 or Class 4 locations that do not have traceable, verifiable, and complete records necessary to establish MAOP under § 192.619. Previously, the provisions were applicable to those pipeline segments without traceable, verifiable, and complete subpart J pressure test records. Similarly, the GPAC recommended that the MAOP reconfirmation provisions only apply to grandfathered pipelines in HCAs, Class 3 or Class 4 locations, or MCAs able to accommodate inspection with ILI tools, and that have MAOPs producing a hoop stress greater than or equal to 30 percent SMYS. In the NPRM, the provisions applied to all grandfathered pipelines in those locations regardless of SMYS. In making this recommendation, the GPAC also suggested PHMSA review the costs and benefits of applying the MAOP reconfirmation provisions to non-HCA Class 3 and Class 4 grandfathered pipe with MAOPs less than 30 percent SMYS.

During the meeting on March 27, 2018, the GPAC also recommended revisions to other sections related to the applicability of MAOP reconfirmation provisions, including withdrawing the proposed revisions to § 192.503, which tied general requirements of the subpart J pressure test to alternative MAOP and MAOP reconfirmation provisions, and withdrawing the proposed revisions to § 192.605(b)(5), which cross-referenced several sections related to the MAOP reconfirmation requirements to the requirements regarding an operator's procedural manuals.

The GPAC also examined the provisions related to the completion date of these actions and recommended that PHMSA revise the appropriate paragraph to account for pipelines that may be subject to these requirements in the future, such as for pipelines that are not in an HCA or Class 3 or Class 4 location now, but due to population growth or development may be in such a location in the future. More specifically, the GPAC recommended that an operator would have to complete all actions required by the MAOP reconfirmation provisions on 100 percent of their pipelines that meet the applicability requirements by 15 years after the effective date of the rule or as soon as practicable but no later than 4 years after the pipeline segment first meets the applicability conditions, whichever is later. The GPAC also recommended PHMSA consider a waiver or no-objection procedure if operators cannot meet the requirements within 4 years under this scenario.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the applicability of MAOP reconfirmation. After considering these comments and as recommended by the GPAC input, PHMSA is modifying the rule to address many of these comments.

Regarding the applicability of the new MAOP reconfirmation requirements at § 192.624, PHMSA notes that a simplistic repeal of the ''grandfather clause'' at § 192.619(c) is not practical because it applies to gathering and distribution lines. As the proposed rule was primarily focused on the safety of gas transmission pipelines, a broad repeal of the grandfather clause was not contemplated in the proposed rule. Further, a major expansion of the MAOP reconfirmation requirements beyond the scope of the congressional mandate in the 2011 Pipeline Safety Act would be costly, and the GPAC noted at the meeting on March 26, 2018, that there may be cost-benefit concerns to test all grandfathered pipelines. The GPAC recommended PHMSA analyze requiring operators to reconfirm the MAOP of all grandfathered lines, and PHMSA considered this as an alternative in the RIA.[65]

In response to the comments received and the recommendations of the GPAC, PHMSA is modifying the applicability of the MAOP reconfirmation requirements as follows: (1) The applicability related to pipeline segments with past in-service incidents is being eliminated. As commenters mentioned, operational failures are already addressed within integrity management and other subparts of part 192. Section 192.617, for example, would require an operator of a gas transmission line that had an in-service incident caused by an incorrect MAOP to determine the proper MAOP of the segment before placing it back into service. Causes of in-service failures are also already incorporated into the risk analyses required by the current IM regulations. If the cause of an incident is an incorrect MAOP, for example, then operators would be required to reconfirm it following the incident within their IM program. However, PHMSA is adding a new paragraph to strengthen the IM requirements at § 192.917(e)(6) to specifically include actions operators must take to address pipeline segments susceptible to cracks and crack-like defects. (2) PHMSA is also modifying the applicability of these requirements by specifying the MAOP reconfirmation requirements are applicable to pipeline segments that do not have the pipeline physical properties and attributes needed to establish MAOP documented in traceable, verifiable, and complete records, specifically those records required to establish and substantiate the MAOP in accordance with § 192.619(a), including those records required under § 192.517(a). More specifically, these requirements to verify MAOP would apply to such pipelines without traceable, verifiable, and complete records in HCAs and Class 3 and Class 4 locations as specified in the congressional mandate. Further, PHMSA is dropping the word ''reliable'' from the applicability section of the regulatory text to be consistent with previous PHMSA advisory bulletins on this topic.[66] (3) PHMSA is modifying the applicability of the MAOP reconfirmation provisions for ''grandfathered'' pipeline segments to pipelines with an MAOP greater than or equal to 30 percent of SMYS, as specified in the congressional mandate. In addition to these requirements applying to grandfathered pipelines in HCAs, PHMSA is retaining the MAOP reconfirmation applicability requirement for grandfathered pipeline segments in Class 3 and Class 4 locations and in piggable MCAs to address the NTSB recommendation on this topic. As per the committee's suggestion, PHMSA analyzed whether it would be feasible to make the MAOP reconfirmation requirements applicable to non-HCA Class 3 and Class 4 pipe operating below 30 percent SMYS. This analysis is presented as an alternative in the RIA for this rulemaking. Ultimately, PHMSA did not choose to include these categories of pipelines in the scope for the applicability of the MAOP reconfirmation requirements because the GPAC recommended it was cost-effective for the provision to only apply to pipe operating above 30 percent SMYS in Class 3 and 4 locations and because those pipelines present the greatest risk to safety.

With respect to the completion date, PHMSA acknowledges the comments received stating that pipeline segments could meet applicability criteria at some point in the future such that it would be difficult or impossible to meet the 15-year deadline for completion. Therefore, PHMSA agrees with the GPAC recommendation discussed above and is modifying the requirements in this final rule to include an alternative completion deadline of 4 years for pipeline segments that meet the applicability standards at some point in the future, for example for those pipeline segments that were in non-HCA locations that later become HCA locations. However, PHMSA emphasizes that this 4-year timeframe does not supersede, invalidate, or otherwise modify the existing requirements in § 192.611 for operators to confirm or revise the MAOP of

[65] See section 5.9.1 of the RIA for further details.

[66] Pipeline Safety: Verification of Records; 77 FR 26822; May 7, 2012; *https://www.govinfo.gov/content/FR-2012-05-07/pdf/2012-10866.pdf*.

segments within 24 months of a change in class location.

PHMSA also acknowledges that some commenters thought the 15-year compliance timeframe for MAOP reconfirmation was too long. PHMSA believes a 15-year timeframe is necessary to be consistent with § 192.939, which allows operators to use a confirmatory direct assessment to confirm their MAOP in two, 7-year inspection cycles. This timeframe was discussed by the GPAC and was approved by unanimous vote. PHMSA will note that operators are required to have 50 percent of the applicable mileage completed within 8 years of the effective date of the rule. PHMSA would expect operators to prioritize and reconfirm the MAOP of the highest-risk segments first.

PHMSA is also withdrawing miscellaneous revisions to § 192.503, which tied general requirements of the subpart J pressure test to alternative MAOP and MAOP reconfirmation provisions, and miscellaneous revisions from § 192.605(b)(5), which cross-referenced several sections related to MAOP requirements to the requirements regarding an operator's procedural manuals. These changes were made to simplify the regulations.

Additionally, because PHMSA has eliminated pipeline segments with past in-service incident history from the scope of the MAOP reconfirmation requirements, PHMSA is striking the proposed references within the MAOP reconfirmation requirements to the alternative MAOP requirements at § 192.620(a)(ii). Operators who used the alternative requirements to establish the MAOP of their pipelines were required to have complete documentation [67] and therefore would not be subject to the MAOP reconfirmation requirements. If an operator had previously established the MAOP of a pipeline segment under the alternative MAOP requirements, but has since lost the records necessary to validate the alternative, they would have to reconfirm MAOP using the alternative MAOP requirements, or apply for a special permit to continue operation.

Per the requirement in section 23 of the 2011 Pipeline Safety Act, PHMSA consulted with members of FERC and State regulators, including representatives from NAPSR and the National Association of Regulatory Utility Commissioners, as appropriate, to establish the timeframes for completing MAOP reconfirmation. As a part of this consultation, which occurred as a function of the GPAC meetings from 2017 through 2018, PHMSA accounted for potential consequences to public safety and the environment while also accounting for minimal costs and service disruptions. These representatives provided both input and positive votes that the provisions surrounding MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if certain changes were made. As previously discussed, PHMSA has taken the GPAC's input into consideration when drafting this final rule and made the according changes to the provisions.

B. MAOP Reconfirmation—§§ 192.624 & 192.632

ii.—Methods

In developing regulations to reconfirm MAOP where necessary, Congress mandated that PHMSA consider safety testing methodologies that include pressure testing and other alternative methods, including in-line inspections, determined to be of equal or greater effectiveness. The NTSB recommended an expansive pressure test approach to address the safety issues identified in their investigation of the PG&E incident through recommendations P–11–14 and P–11–15. In response to the congressional mandate, PHMSA evaluated other methodologies and identified five additional methods that could provide an equivalent or greater level of safety. Therefore, PHMSA proposed to allow the following six methods for MAOP reconfirmation, including the conventional pressure test method.

Summary of PHMSA's Proposal: Method 1—Pressure Test

A pressure test is the most conventional assessment method by which an operator may reconfirm a pipeline segment's MAOP. PHMSA proposed standards for conducting pressure tests for MAOP reconfirmation in part to meet the intent of NTSB recommendations P–11–14 and P–11–15. First, PHMSA proposed minimum test pressure standards where a pipeline segment's MAOP would be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor. Second, if the pipeline segment might be susceptible to cracks or crack-like defects,[68] then the operator must incorporate a spike pressure feature into the pressure test procedure. PHMSA proposed standards for the spike hydrostatic test in § 192.506. If the operator has reason to believe any pipeline segment may be susceptible to cracks or crack-like defects, the operator would be required to also estimate the remaining life of the pipeline in accordance with the same standards specified in Method 3, the engineering critical assessment method.

Summary of Public Comment: Method 1—Pressure Test

Several commenters opposed the proposed provisions requiring a spike test to be conducted as part of the pressure test for the purposes of MAOP reconfirmation, and these comments are discussed further under the ''spike test'' portion of the proposal and comment summary of this rulemaking.

API suggested that a pipeline segment's MAOP can be best established through performing a combination of pressure tests and ILI examinations, and they discussed how operators could conduct hydrostatic pressure testing to determine the in-place yield strength of a segment of pipeline by conducting a ''spike'' test pressure held for a few minutes followed by a subpart J pressure test approximately 10 percent below the spike level. API further stated that using ILI tools in conjunction with this method would further substantiate the results, as geometry ILI tools capable of measuring inside diameter to detect yielding could further substantiate and quantify the results of the pressure test.

AGA stated that while they believe that pressure testing is a straightforward and well-established method, the proposed Method 1 MAOP reconfirmation requirements are unnecessarily complex. AGA further stated that subpart J provides different requirements and specifications for pressure tests based on the type of pipe being tested, and that Method 1 should refer to subpart J rather than to § 192.505(c) specifically, which requires unnecessarily stringent requirements. PG&E supported the proposed provisions and committed to pressure testing all pipes.

INGAA stated that since the basic strength properties of steel pipe do not change over time, PHMSA should not limit allowable tests to only those conducted after July 1, 1965, as was proposed in § 192.619(a)(2)(ii). They emphasized that the test parameters, not

[67] ''Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines; Final Rule;'' October 17, 2008; 73 FR 62148. The effective date of the rule was November 17, 2008.

[68] These pipelines can include pipelines constructed with ''legacy pipe'' or using ''legacy construction techniques;'' pipelines with evidence or risk of stress corrosion cracking or girth weld cracks; or pipelines that have experienced an incident due to an original manufacturing-related defects, construction-related defects, installation-related defects, or fabrication-related defects.

the test date, should be considered for MAOP reconfirmation. Further, INGAA stated that recognizing the validity of earlier tests would not necessarily mean that no further pressure tests would be conducted, as periodic testing may be required to ensure the continued integrity of the pipeline segment under the operator's integrity management program. However, such additional tests are managed under IM, which is separate from MAOP reconfirmation.

Certain commenters stated that a spike test is not required to establish an adequate margin of safety for MAOP reconfirmation and suggested PHMSA eliminate spike testing from the pressure test method of MAOP reconfirmation.

Regarding the proposed definitions of ''legacy pipe'' and ''legacy construction,'' AGA and Xcel Energy commented that as proposed, the definitions could be interpreted to apply to distribution pipelines as well as gas transmission pipelines. Commenters requested that PHMSA explicitly exclude distribution pipelines from these definitions, which would be applicable to all part 192.

On March 26, 2018, the GPAC recommended that PHMSA delete the spike test requirements from the pressure test method of MAOP reconfirmation. The GPAC also recommended that PHMSA require operators to perform a pressure test in accordance with subpart J of part 192 rather than refer to specific requirements in § 192.505. Further, and as discussed during the meetings of December 2017 and March 26, 2018, if the applicable pressure test segment does not have traceable, verifiable, and complete MAOP records, the operator must use the best available information upon which the MAOP is currently based to conduct the pressure test. The GPAC recommended PHMSA create a requirement for the operator of such a pipeline segment to add the test segment to its plan for opportunistically verifying material properties in accordance with the material properties verification provisions. During the meeting, PHMSA noted that most pressure tests would present at least two opportunities for material properties verification at the test manifolds.

PHMSA Response: Method 1—Pressure Test

PHMSA appreciates the information provided by the commenters regarding the pressure test method of MAOP reconfirmation (Method 1). After considering these comments and as recommended by the GPAC, PHMSA is eliminating the spike testing requirement as part of the pressure test method of MAOP reconfirmation. As commenters stated, spike testing is primarily used for the mitigation of cracks and crack-like defects, and PHMSA has determined it would therefore be more appropriate to be placed within the context of threat management under IM. Additionally, PHMSA is removing the definitions for and related references to ''legacy pipe'' and ''legacy construction'' in this final rule because the applicability to pipe with ''legacy pipe or construction'' leaks or failures was dropped from the applicability criteria for MAOP reconfirmation. PHMSA also modified the rule to refer to subpart J pressure tests rather than paragraph § 192.505(c), specifically, and to recognize the validity of earlier pressure tests. Lastly, if an operator does not have traceable, verifiable, and complete records for the material properties needed to establish MAOP by pressure testing, PHMSA is requiring that operators test, in accordance with the material verification requirements, the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. Further, if there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with the material properties verification requirements to ensure that the segment of pipe is consistent with operator's sampling program established under § 192.607. This will avoid issues where operators may not have the documented and verified physical pipeline material properties and attributes that would otherwise be necessary to perform a hydrostatic pressure test to reconfirm MAOP.

Summary of Proposal: Method 2—Pressure Reduction

In the NPRM, PHMSA proposed that pipeline operators could choose to reduce the MAOP of the applicable pipeline segment to reconfirm the segment's MAOP. This approach would use the recent operating pressure as a *de facto* pressure test, and then an operator would set the pipeline segment's MAOP at a slightly lower pressure. PHMSA proposed that operators using this method set the pipeline's MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding the effective date of the final rule divided by the greater of either 1.25 or the applicable class location, which are the same safety factors as used for the pressure testing in Method 1. PHMSA included standards for establishing the highest actual sustained pressure for the purposes of reconfirming MAOP under this method and included standards for addressing class location changes. Additionally, PHMSA proposed that, if the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects, the operator would be required to estimate the remaining life of the pipeline.

Summary of Public Comment: Method 2—Pressure Reduction

AGA commented that the 18-month look-back time frame listed in the pressure reduction MAOP reconfirmation method is a much too narrow time frame for consideration and that the section should be rewritten to clarify that the pressure reduction should be taken from either (1) the immediate past 18 months, or (2) 5 years from the time the last pressure reduction was taken, stating that tying the baseline pressure to the effective date of the rule is arbitrary. Enterprise Products recommended that PHMSA clarify the derating criteria used for pipes that use this method of reconfirming MAOP. Further, Piedmont expressed concern that this method does not account for the actual gap that can occur between MAOP and operating pressure. Some commenters questioned whether the MAOP from which to take a pressure reduction was based on the most recent pressure test or the historical highest-pressure test, and some commenters suggested PHMSA revise this provision to allow operators to reconfirm the MAOP based on the existing MAOP and not using an 18-month look-back period unless an incident caused by a material-related or construction-related defect has occurred on the pipeline since its last subpart J pressure test.

TPA stated that using this method unfairly penalizes operators in situations where the operator has prepared for future needs and has not operated at MAOP for a period greater than 18 months. Similarly, another commenter suggested that operators who have already reduced MAOP on pipeline segments to be proactive should not be penalized by having to take an additional reduction in MAOP.

Some commenters recommended limiting the applicability of this method to those pipelines operating at 30 percent SMYS or greater.

Regarding the pressure reduction method for MAOP reconfirmation, the GPAC recommended PHMSA increase the look-back period from 18 months to 5 years and remove the requirements for operators selecting to take the pressure reduction to reconfirm MAOP to perform fracture mechanics analysis on those pipeline segments.

PHMSA Response: Method 2—Pressure Reduction

PHMSA appreciates the information provided by the commenters regarding the pressure reduction method of MAOP reconfirmation (Method 2). After considering these comments and as recommended by the GPAC, PHMSA is increasing the look-back period to 5 years from the publication date of the rule and is removing the requirements for operators to perform fracture mechanics analysis on those pipeline segments where the operator has selected Method 2. PHMSA made this change because the 5-year look-back period is consistent with IM requirements regarding MAOP confirmation.

Summary of PHMSA's Proposal: Method 3—Engineering Critical Assessment

Method 3 directly addresses the congressional mandate for PHMSA to consider safety testing methodologies that include other alternative methods, including ILI, determined to be of equal or greater effectiveness. Demonstrating that knowledge gained from an ILI assessment provides an equivalent level of safety as a pressure test is technically challenging. PHMSA used best safety practices gained from implementation of integrity management since 2003; development of class location special permits; and technical research on related topics, such as analysis of crack defects and seam defects. PHMSA applied these principles and analytical methods to develop an engineering critical assessment (ECA) methodology, which applies state-of-the-art fracture mechanics analysis to analyze defects in the pipe and determine if those defects would or would not survive a hydrostatic pressure test at the test pressure needed to establish MAOP. In addition, PHMSA proposed that if the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects, the operator would be required to estimate the remaining life of the pipeline using the fracture mechanics standards PHMSA specified.

Summary of Public Comment: Method 3—Engineering Critical Assessment

Several trade associations and pipeline industry entities stated that ILI is the best and most practical method for MAOP reconfirmation due to its cost-effectiveness and environmentally friendly nature, and that PHMSA should allow operators to use ILI as a reconfirmation method. These commenters, however, also stated that the requirements proposed for the usage of ILI with an ECA are overly complicated and burdensome, and they specifically recommended that the final rule should be simplified so that this method will play a greater role in MAOP reconfirmation in lieu of a pressure test. For example, INGAA asserted that PHMSA should remove the requirements in the ECA related to operations, maintenance, and integrity management, arguing that these requirements do not factor into MAOP reconfirmation and would be covered elsewhere in part 192. Further, INGAA proposed additional alternatives for using the ECA method to obtain necessary data for MAOP reconfirmation, asserting that these alternatives would be less burdensome and equally effective. More specifically, INGAA suggested removing duplicate regulatory language, removing the pre-approval process for ILI, and adding unity plots as a method for operators to demonstrate that ILI is reliable for identifying and sizing actionable anomalies. TransCanada and PECO Energy Co. stated that for the ECA method to be used by industry, the detailed requirements listed under this method in the proposed rule should be replaced with the use of standard ECA best practices.

Some commenters suggested that operators have long relied on sound engineering judgments and conservative assumptions to account for record gaps. Commenters stated that, if stripped of the ability to use sound engineering judgment and conservative assumptions, operators would need to substantially invest in processes, procedures, tests, and project engineering and support to develop and implement a comprehensive material properties verification plan as outlined in the proposed regulations. Another commenter asked for clarification on using assumptions of Grade A pipe (30,000 psi) versus the use of 24,000 psi as noted in § 192.107(b)(2) if the SMYS or actual material yield strength and ultimate tensile strength is unknown or is not documented in traceable, verifiable, and complete records.

Another commenter suggested that in cases where a pipeline has been pressure tested, but not to the level of 1.25 times MAOP, PHMSA should allow operators to augment the original test with an ECA and other analysis to reconfirm the pipeline segment's MAOP under method 3.

The PST stated that there are certain cases in which the ECA method should not be allowed as an alternative to pressure testing. Citing a white paper prepared by Accufacts, Inc. on ECA methodology, the PST recommended that PHMSA prohibit the use of the ECA method for determining the strength of a pipeline segment in cases where there are girth weld crack threats, significant stress corrosion cracking threats, or dents with stress concentrator threats.

During the GPAC meeting on March 27, 2018, the GPAC recommended that PHMSA remove the fracture mechanics analysis for failure stress and crack growth analysis requirements from the ECA method of MAOP reconfirmation and move them to a stand-alone section in the regulations. Further, the GPAC recommended that such a section should not specify when, or for which pipeline segments, fracture mechanics analysis would be required. The GPAC suggested that this new fracture mechanics section outline a procedure by which operators perform fracture mechanics analysis when required or allowed by other sections of part 192, which was similar to its treatment of the proposed material properties verification procedures at § 192.607. Under the GPAC's proposal, the ECA method for MAOP reconfirmation would not contain any specific technical fracture mechanics requirements or Charpy V-notch toughness values but would instead refer to the new fracture mechanics section. Other recommendations related specifically to the new fracture mechanics section are discussed in that area of the proposal and comment summary section of this document.

The GPAC also recommended PHMSA add a requirement to verify material properties in accordance with the rule's material properties verification provisions if the information needed to conduct a successful ECA is not documented in traceable, verifiable, and complete records.

PHMSA Response: Method 3—Engineering Critical Assessment

PHMSA appreciates the information provided by the commenters regarding the ECA method of MAOP reconfirmation (Method 3). As recommended by the GPAC, PHMSA is removing the fracture mechanics analysis requirements from the ECA method of MAOP reconfirmation and moving them to a new stand-alone § 192.712. PHMSA agrees this change will improve comprehension of the regulations. This new section does not specify when, or for which pipeline segments, fracture mechanics analysis would be required but instead outlines a procedure by which operators perform fracture mechanics analysis when required by other sections of part 192. Section 192.712 is referenced in the pressure reduction, ECA, and ''other technology'' methods of MAOP reconfirmation under § 192.624, as well as in § 192.917 for cyclic fatigue loading. Therefore, the ECA method for MAOP reconfirmation does not contain any specific technical fracture mechanics requirements or Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) but instead refers to the new § 192.712. Comments related to the assumptions an operator can use when material properties are unknown are addressed in the discussion on § 192.712 below. PHMSA also added a requirement to verify material properties in accordance with the rule's material properties verification provisions at § 192.607 if the information needed to conduct a successful ECA is not documented in traceable, verifiable, and complete records.

PHMSA disagrees that the additional analytical requirements, beyond ILI, are overly complicated or burdensome. To conclude that an ECA is of equal or greater effectiveness as a pressure test for the purposes of MAOP reconfirmation, as mandated by Congress, more than an ILI and repair program is required. A pressure test proves that any flaws in the pipe are small enough to hold the test pressure without leaking. Such subcritical flaws must be analyzed to prove that they would pass a pressure test, even if the pressure test is not conducted. A fracture mechanics analysis is capable of reliably drawing such conclusions but must be carefully and capably performed. Such an analysis also requires accurate data. In the absence of reliable data for key parameters, such as fracture toughness, PHMSA allows the use of appropriately conservative assumptions. This is discussed in more detail in the sections below.

Based on an ASME report and research sponsored by PHMSA,[69] the ECA analysis can be reliably used to ascertain if a pipeline segment would pass a pressure test, even if it has seam weld cracking, and the final rule includes requirements for conducting ILI using tools capable of detecting girth weld cracks. The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of each defect.

PHMSA also notes that the final rule addresses cases where a pipeline has been pressure tested, but not to the level of 1.25 times MAOP, by allowing operators to account for those test results and augment the original test with an ECA, or conduct an ILI tool assessment program to characterize defects remaining in the pipe along with using an ECA to establish MAOP, to reconfirm the pipeline segment's MAOP using Method 3. Detailed ILI requirements are addressed in new § 192.493, which is discussed in more detail below.

PHMSA is moving the ECA process requirements in this final rule to a new stand-alone § 192.632. Section 192.624(c)(3) (ECA method of MAOP reconfirmation) and the new § 192.632 will cross-reference each other. PHMSA decided to make this change when finalizing this rulemaking only to improve the readability of the regulations. No substantive changes were made to the requirements in connection with this organizational change.

Summary of PHMSA's Proposal: Method 4—Pipe Replacement

When reconfirming MAOP on certain pipeline segments, some operators may face significant technical challenges or costs when performing either a pressure test or an ILI examination, and it may be more economically viable to replace the pipeline. Therefore, PHMSA proposed to allow pipe replacement for operators to reconfirm their MAOP. In such cases, the replacement pipeline would be designed, constructed, and pressure tested according to current standards to establish MAOP.

Summary of Public Comment: Method 4—Pipe Replacement

Commenters, including Mid-American Energy Company and Paiute Pipeline, stated their support for this method. The GPAC similarly supported this method and did not recommend any changes for this aspect of MAOP reconfirmation.

PHMSA Response: Method 4—Pipe Replacement

PHMSA appreciates the information provided by the commenters regarding the pipe replacement method of MAOP reconfirmation (Method 4). After considering these comments and as recommended by the GPAC, PHMSA is retaining the proposed rule text for Method 4 in the final rule.

Summary of PHMSA's Proposal: Method 5—Pressure Reduction for Small, Low-Pressure Pipelines

For low-pressure, smaller-diameter pipeline segments with small potential impact radii (PIR), PHMSA proposed an MAOP reconfirmation method similar to the pressure reduction under Method 2. Operators of pipeline segments for which (1) the MAOP is less than 30 percent SMYS, (2) the PIR is less than or equal to 150 feet, (3) the nominal diameter is equal to or less than 8 inches,[70] and (4) which cannot be assessed using ILI or a pressure test, may reconfirm the MAOP as the highest actual operating pressure sustained by the pipeline segment 18 months preceding the effective date of the final rule, divided by 1.1. In addition to this pressure reduction, operators of these lines would be required to perform external corrosion direct assessments in accordance with the IM provisions, develop and implement procedures to evaluate and mitigate any cracking defects, conduct a specified number of line patrols at certain intervals, conduct periodic leak surveys, and odorize the gas transported in the pipeline segment.

Summary of Public Comment: Method 5—Pressure Reduction for Small, Low-Pressure Pipelines

AGA stated that PHMSA did not provide enough justification for imposing the additional pressure reduction requirements listed under this method, asserting that this method should require either a 10 percent pressure reduction or the implementation of additional preventative actions that are feasible and practical, but not both. TPA stated that the 18-month criterion penalizes operators who may have operated pipelines at lower capacities to anticipate future needs. Furthermore, TPA urged PHMSA to limit the requirements for MAOP reconfirmation under Method 5 to the reduction in MAOP and not impose additional safety requirements, stating that these pipelines are generally considered low-stress pipelines and that their risk of rupture is very low. Similarly, API stated that the proposed requirements for odorization and frequent instrumented leak surveys are impractical. Some commenters felt that the terms for small potential impact radius and the applicable diameters should be defined.

[69] See: American Society of Mechanical Engineers (ASME) Standards Technology Report ''Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'' (STP–PT–011), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1'' (Task 4.5); *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.*

[70] 8.625 inches actual diameter.

On March 27, 2018, the GPAC recommended PHMSA delete the size and pressure criteria of this method and base the applicability solely on a potential impact radius of less than or equal to 150 feet. The GPAC also recommended increasing the look-back period to 5 years from 18 months. Further, the GPAC recommended PHMSA strike the additional requirements in this method related to external corrosion direct assessment, crack analysis, gas odorization, and fracture mechanics analysis. They also recommended PHMSA change the frequency of patrols and surveys to 4 times a year for Class 1 and Class 2 locations, and 6 times per year for Class 3 and Class 4 locations.

PHMSA Response: Method 5—Pressure Reduction for Small, Low-Pressure Pipelines

PHMSA appreciates the information provided by the commenters regarding the pressure reduction method of MAOP reconfirmation for small, low-pressure pipelines (Method 5). After considering these comments and as recommended by the GPAC, PHMSA is deleting the pipeline segment size and pressure criteria of this method and basing the applicability solely on a potential impact radius of less than or equal to 150 feet. PHMSA believes this change streamlines the regulations while maintaining pipeline safety. PHMSA is increasing the look-back period to 5 years, which is consistent with other sections of part 192, including integrity management. Additionally, PHMSA is deleting the requirements in this method related to external corrosion direct assessment, crack analysis, gas odorization, and fracture mechanics analysis. PHMSA is also changing the frequency of patrols and surveys to 4 times a year for Class 1 and Class 2 locations, and 6 times per year for Class 3 and Class 4 locations. PHMSA believes these changes increase regulatory flexibility while maintaining pipeline safety.

Summary of Proposal: Method 6—Alternative Technology

PHMSA proposed that operators may use an alternative technical evaluation process that provides a documented engineering analysis for the purposes of MAOP reconfirmation. If an operator elects to use an alternative method for MAOP reconfirmation, it would have to notify PHMSA and provide a detailed fracture mechanics analysis—including the safety factors—to justify the establishment of the MAOP using the proposed alternative method. The notification would have to demonstrate that the proposed alternative method would provide an equivalent or greater level of safety than a pressure test. PHMSA included this option to allow and encourage the continual research and development needed to improve state-of-the-art fracture mechanics analysis, integrity assessment methods, advances in metallurgical engineering, and new techniques.

Summary of Public Comment: Method 6—Alternative Technology

For the alternative technologies method of MAOP reconfirmation, several stakeholders opposed the timeframes, case-by-case approval process, and procedural barriers PHMSA proposed for using this method. Several commenters, including Cheniere Energy, Delmarva Power & Light, and INGAA, suggested that the procedural hurdles required by the proposed provisions would make this option difficult for operators to use for MAOP reconfirmation as well as for any other provisions PHMSA allows alternative technology use with notification. More specifically, these commenters suggested that a process whereby PHMSA could object to the use of an alternative technology at any time during a project's lifecycle does not provide the level of certainty necessary for operators to move forward with using alternative technologies. That uncertainty would deter the development of what could be better or safer alternatives.

Piedmont stated that it does not believe that the role of PHMSA includes determining the appropriate technologies to be used to reconfirm MAOP. Piedmont further stated that currently under subpart O, operators are required to obtain approval from PHMSA to use alternative technologies for integrity assessment, and that operators have waited more than 180 days for PHMSA to respond to these requests. Piedmont stated that this uncertainty cannot be reconciled with the planning and business considerations that an operator must consider when evaluating how to invest in technology and which methods to use for establishing MAOP. The PST stated that the approval process should be similar to the process used for special permits and that before these methods are approved by PHMSA, they should be subject to public review and comment under the National Environmental Policy Act of 1969 (NEPA).

At the meeting on March 27, 2018, the GPAC recommended PHMSA incorporate the 90-day notification and objection procedure for the use of alternative technology. To summarize, operators would have to notify PHMSA of its intent to use other technology, and PHMSA would have 90 days to respond with an objection if PHMSA had one, or a need for more review time. Otherwise, the operator would be free to use the proposed method or technology.

PHMSA Response: Method 6—Alternative Technology

PHMSA appreciates the information provided by the commenters regarding the other technology method of MAOP reconfirmation (Method 6). After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to incorporate the 90-day notification and objection procedure the committee recommended. Operators would have to notify PHMSA of its intent to use other technology to reconfirm MAOP in accordance with § 192.18, and PHMSA would have 90 days to respond with an objection if PHMSA had one or a notice that PHMSA required more time for its review, which would extend the timeframe. Without a notice of objection or additional review by PHMSA, the operator would be allowed to use the alternative technology. PHMSA has successfully applied the notification process to other technology assessments under subpart O since its inception and does not believe a special permit process is warranted for every notification for alternative technology. PHMSA believes the changes made in the final rule will address the concerns about timeliness of notification reviews by PHMSA.

B. MAOP Reconfirmation—§ 192.624

iii.—Spike Test

1. Summary of PHMSA's Proposal

The ''spike'' hydrostatic pressure test is a special feature of the pressure testing method of MAOP reconfirmation. PHMSA intends this aspect of the MAOP reconfirmation process to address the intent of NTSB recommendations P–11–14 (related to spike testing for grandfathered pipe) and P–11–15 (related to pressure testing to show that manufacturing and construction-related defects are stable).

PHMSA proposed that a spike test would be required for cases where a pipeline segment might be susceptible to cracks or crack-like defects. Such pipe may include ''legacy pipe;'' pipe constructed using ''legacy'' construction techniques; pipelines that have experienced an incident due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect; or pipe with stress corrosion cracking or girth weld cracks. Cracks and crack-like defects in some cases may be susceptible to a phenomenon called ''pressure reversal,'' which is the failure of a defect at a pressure less than a pressure level that the flaw has previously experienced and survived. The increased stress from the test pressure may cause latent cracks that are almost, but not quite, large enough to fail to grow during the test. If the crack does not fail before the test is completed, the resultant crack that remains in the pipe may be large enough to no longer be able to pass another pressure test. The spike portion of the pressure test is designed to cause such marginal crack defects to fail during the early, spike phase of the pressure test. The post-spike, long-duration test pressure validates the operational strength of the pipe. Using a short-duration, very high spike pressure followed by a long-duration integrity verification pressure provides greater assurance that the test is not ''growing cracks'' that could fail in-service after the test is completed. PHMSA proposed standards for the spike hydrostatic test in § 192.506. PHMSA used several technical reports and studies, including PHMSA-sponsored research, to inform the standards proposed for the spike test. Those materials include, American Society of Mechanical Engineers Standards Technology Report ''Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'' (STP–PT–011), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1'' (Task 4.5).[71]

2. Summary of Public Comment

Some commenters supported the concept of requiring the use of a spike hydrostatic pressure test as part of the MAOP reconfirmation process for establishing MAOP but expressed concern over specific aspects of the provision. For example, AGA urged PHMSA to allow pneumatic pressure tests as well as hydrostatic pressure tests. In addition, AGA disagreed with the allotted test duration provided in the proposal. Similarly, other operators who commented, such as CenterPoint Energy and Dominion East Ohio, stated that the proposed spike test target hold pressure of 30 minutes exceeds the time needed to determine the mechanical integrity of the pipeline test segment and will cause pre-existing crack-like defects to grow. Alternatively, Dominion Transmission, Tallgrass Energy Partners, SoCalGas, and Paiute Pipelines stated that a test level of 100 percent SMYS, not 105 percent SMYS, would be sufficient to remediate cracking threats. Enterprise Products stated that the requirements for the design of a spike test should be based on integrity science, such as fatigue life and reassessment intervals, and suggested PHMSA's proposed spike test pressure limits were set at an arbitrary level. Enterprise further stated that the utility of stressing a pipe beyond 100 percent of its yield strength is questionable and potentially damages the pipe. Other commenters, including MidAmerican Energy Co., requested that pneumatic spike tests to 1.5 times MAOP be allowed when the resultant pressure complies with the limitations stated in the table in § 192.503(c).

Trade associations and pipeline industry entities, including INGAA, GPA, and TPA, asserted that PHMSA should eliminate the spike test requirement for establishing MAOP entirely. These commenters stated that the proposed provisions went beyond what was required to reconfirm MAOP for an accepted margin of safety. These commenters further asserted that spike testing is not an appropriate technique for MAOP reconfirmation, and it could result in unintended negative consequences without improving pipeline safety. They stated that spike testing is an aggressive and destructive technique that should be used only in cases in which time-dependent threats, such as a significant risk of stress corrosion cracking, exist.

INGAA and other commenters agreed with PHMSA that the use of spike hydrostatic testing is appropriate for time-dependent threats, such as stress corrosion cracking. INGAA, however, suggested changes to the proposed spike hydrostatic pressure test provisions and the cross-reference to those provisions in the proposed IM assessment method revisions to limit the spike testing requirement to time-dependent threats, to test to a minimum of 100 percent SMYS instead of 105 percent, and to provide an alternative for use of an instrumented leak survey. INGAA agreed that spike testing is the best means of testing a pipeline with a history of environmental cracking, such as stress corrosion cracking that has developed while a pipeline is in service, and noted that a spike test may be of value for in-service pipelines where metallurgical fatigue is of concern. INGAA further stated that pressure cycling should not need to be included in the proposed spike test provisions and that PHMSA should amend the proposed rule to limit spike testing only to those pipeline segments with stress corrosion cracking.

An additional commenter suggested PHMSA should allow operators to use the short-duration spike portion of a spike pressure test to determine the lower bound of the yield strength of the test section, including all pipe and components that are subjected to the test pressure. Such a test, if used for this purpose, must also confirm that yielding beyond that experienced in a standard tensile test to determine yield strength, typically on the order of 0.5 percent, has not occurred. This confirmation may be demonstrated by data from a pressure-volume plot of the test or a post-test geometry tool in-line inspection.

Public interest and other groups, including Pipeline Safety Coalition, Environmental Defense Fund (EDF), and NAPSR, expressed support for spike testing, stating that it would provide for increased pipeline safety. NAPSR further stated that the option of applying to use alternative technology or an alternative technological evaluation process would allow for some flexibility in cases in which a hydrostatic test is impractical. EDF also suggested additional measures to mitigate emissions from methane gas lost during testing.

At the GPAC meeting on March 2, 2018, the GPAC recommended that PHMSA revise the spike test requirements to change the minimum spike pressure to the lesser of 100 percent SMYS or 1.5 times MAOP, reduce the spike hold time to a minimum of 15 minutes after the spike pressure stabilizes, revise the applicable language to refer specifically to ''time-dependent'' cracking, incorporate the 90-day notification and objection procedure discussed for other sections, and adjust the SME requirements by adding language describing a ''qualified technical subject matter expert'' where applicable.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the requirements for spike pressure testing. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to change the minimum spike pressure to the lesser of 100 percent SMYS or 1.5 times MAOP, as PHMSA believes these pressures are sufficient to maintain pipeline safety. PHMSA is specifying a spike hold time of a minimum of 15 minutes after the spike pressure stabilizes, rather than a 30-minute overall hold time, to be consistent with pipeline safety. Additionally, PHMSA is

[71] *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.*

modifying the rule to revise the applicable language to refer specifically to ''time-dependent'' cracking, incorporate the same notification procedure under § 192.18 with the 90-day timeframe for objections or requests for more review time, and adjust the SME requirements by using broader language describing a ''qualified technical subject matter expert'' where applicable instead of specifying technical fields of expertise such as metallurgy or fracture mechanics. PHMSA believes these changes increase regulatory flexibility while maintaining pipeline safety.

In addition, as stated above, the spike test is being removed from the MAOP reconfirmation requirements. The spike test procedure in the new § 192.506 would be used whenever required by other requirements in part 192 to address crack remediation and the integrity threat of cracks and crack-like defects.

PHMSA disagrees with allowing pneumatic spike tests to 1.5 times MAOP based on safety concerns. Pneumatic pressure tests are allowed in § 192.503(c), with certain limitations, for new, relocated, or replaced pipe. For new, relocated, or replaced pipe, there is knowledge that the pipe is likely sound and is usually manufactured with recent mill pressure tests to confirm the pipe meets applicable standards. A spike test to perform an integrity assessment on *in-situ* pipe with known or suspected cracks or crack-like defects presents a much higher likelihood of the pipeline segment experiencing a leak or rupture during the test with resultant consequences, including the possibility of fire or explosion. PHMSA notes that conducting a pneumatic test using a compressible gas, such as air, nitrogen, or methane, would be a safety concern for the public and operating personnel. Gas that is highly compressed has stored energy that would be suddenly released should there be a flaw in the pipe. Liquids, such as water, do not have the stored energy release that a compressible gas has should the pipe have a flaw that either leaks or ruptures. Therefore, the safety risk of performing a hydrostatic pressure test (with water) is much lower due to the less-compressible nature of liquids. Compressed gas would be a fire or explosion hazard to the public. However, as specified in the proposed and final rules, operators that desire to use a pneumatic spike test may propose using such a test, with justification, by submitting a notification to PHMSA.

B. MAOP Reconfirmation—§ 192.624

iv.—Fracture Mechanics

1. Summary of PHMSA's Proposal

In the proposal, PHMSA determined that fracture mechanics analysis is a key aspect of meeting the congressional mandate to consider safety testing methodologies for MAOP reconfirmation of equal or greater effectiveness as a pressure test, including other alternative methods such as ILI. Demonstrating that knowledge gained from an ILI assessment provides an equivalent level of safety as a pressure test is technically challenging. An ILI assessment might reveal the presence of crack flaws and crack-like defects and characterize them within the accuracy of tool performance capabilities, but determining whether those cracks would survive a pressure test to reconfirm MAOP requires very in-depth and highly technical analysis. Such an analysis not only requires an accurate characterization of cracks, it also requires accurate and known metallurgical properties of the pipe. To address these aspects, PHMSA proposed more detailed requirements in § 192.921 for evaluating defects discovered during ILI to account for tool accuracy and other factors to accurately characterize flaw dimensions and support accurate fracture mechanics analysis. In addition, the material properties verification and documentation requirements PHMSA proposed are critical to performing fracture mechanics analysis of ILI-discovered defects that would be accurate enough to establish MAOP in a way that is demonstrably equivalent in safety to a pressure test. In the MAOP reconfirmation provisions, PHMSA proposed new requirements for fracture mechanics analysis for failure stress and cracks, listing specific requirements, standards, and data operators must use when performing a fracture mechanics analysis.

2. Summary of Public Comment

Most industry stakeholders were opposed to the proposed fracture mechanics requirements. AGA, New Mexico Gas Co., and TPA suggested that fracture mechanics have a limited place in preventing pipeline failures or predicting them accurately and should not be a component of MAOP reconfirmation. AGA stated that the rule should not prescriptively require fracture mechanics calculations to be performed for a broad range of applications but should be narrowed to include only transmission pipelines operating at a hoop stress greater than 30 percent SMYS, given that pipelines that operate below 30 percent SMYS have a strong tendency to leak rather than rupture.

Commenters also stated that requiring fracture mechanics as any part of the MAOP reconfirmation process was overly burdensome and unclear. Specifically, API stated that some of the requirements listed under the MAOP reconfirmation requirements were overly conservative and burdensome for most situations where this technique would be used. For instance, a commenter noted that there is no non-destructive evaluation (NDE) methodology for obtaining Charpy V-notch toughness values. Therefore, PHMSA's requirement to obtain Charpy V-notch toughness values eliminates the availability of non-destructive testing. Further, a commenter noted that the proposed ECA analysis prescribed a body toughness of 5-ft.-lbs. and a seam toughness of 1-ft.-lbs., which are arbitrary and very conservative. Vintage pipelines will not have Charpy V-notch toughness data, and requiring an overly conservative assumption of toughness is not reasonable. Toughness can vary depending on the manufacturer, the manufacturing method, and the pipe vintage, and it should not be prescribed in the regulations. The commenter further noted that using the conservative defaults, especially the overly conservative defaults PHMSA proposed, may result in an unacceptably short remaining life of the pipeline.

Similarly, commenters recommended PHMSA allow alternative methods of assessing strength properties that provide a suitable lower bound to the actual strengths. Allowing alternative methods will provide flexibility to consider conservative, but realistic, estimates of material properties. Commenters also stated that SMEs in both metallurgy and fracture mechanics are not needed to validate non-destructive test (NDT) methods. Engineers with knowledge in test validation methods but not necessarily metallurgy and fracture mechanics are capable of validating NDT methods.

More broadly, Energy Transfer Partners suggested that the proposed language for fracture mechanics is misplaced in MAOP reconfirmation and should be moved to the proposed requirements for non-HCA assessments, or elsewhere, since this text more closely resembles an ''assessment.'' Other commenters agreed with that concept, suggesting fracture mechanics is more appropriate under the IM measures for threat mitigation rather than for MAOP reconfirmation.

As previously discussed in this document, the GPAC recommended

PHMSA move the fracture mechanics analysis requirements out of the ECA method of MAOP reconfirmation and into a new stand-alone section in the regulations, making it a process for performing fracture mechanics analysis whenever required or allowed by part 192. The committee therefore recommended that PHMSA delete any cross-references to the MAOP reconfirmation and the spike pressure test provisions. The GPAC also recommended that operators make and retain specific records to document fracture mechanics analyses performed.

Along with moving the fracture mechanics analysis requirements to a stand-alone section, the GPAC had several specific recommendations related to how the requirements would function. The GPAC recommended PHMSA remove ILI tool performance specifications and replace them with a requirement for operators to verify tool performance using unity plots or equivalent technologies, and also recommended revisions to the fracture mechanics requirements by striking the sensitivity analysis requirements and replacing them with a requirement for operators to account for model inaccuracies and tolerances.

As it pertains to the Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) used in fracture mechanics analysis, the GPAC recommended that operators could use a conservative Charpy V-notch toughness value based on the sampling requirements of the material properties verification provisions or use Charpy V-notch toughness values from similar-vintage pipe until the actual properties are obtained through the operator's opportunistic testing program. The GPAC recommended that PHMSA clarify that default Charpy V-notch toughness values of 13-ft.-lbs. for pipe body and 4-ft.-lbs. for pipe seam only apply to pipe with suspected low-toughness properties or unknown toughness properties. Further, if a pipeline segment has a history of leaks or failures due to cracks, the GPAC recommended PHMSA require the operator to work diligently to obtain any unknown toughness data. In the interim, operators of such pipeline segments must use Charpy V-notch toughness values of 5-ft.-lbs. for pipe body and 1-ft.-lbs. for pipe seam. The GPAC also recommended PHMSA include a 90-day notification procedure similar to the previously agreed-upon procedure if operators wanted to request the use of differing Charpy V-notch toughness values.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed fracture mechanics requirements. After considering these comments and as recommended by the GPAC, PHMSA is moving the fracture mechanics analysis requirements out of the ECA method of MAOP reconfirmation and into a new stand-alone § 192.712 in the regulations, making it a process by which operators must perform fracture mechanics analysis whenever required by part 192. This change was made to increase the readability of the regulations. As a part of making these provisions into a stand-alone section in the regulations, PHMSA is also deleting the references within § 192.712 to the MAOP reconfirmation and the spike pressure test provisions. PHMSA is adding a requirement for operators to make and retain specific records documenting any fracture mechanics analyses performed. PHMSA is also removing ILI tool performance specifications and sensitivity analysis requirements and replacing them with a requirement for operators to verify tool performance using unity plots or equivalent technologies and to account for model inaccuracies and tolerances. This change will increase regulatory flexibility while maintaining pipeline safety.

Regarding the default Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) used in fracture mechanics analysis when actual values are not known, industry and the GPAC had significant comments. PHMSA is aware of pipe manufactured per API Specification 5L in this decade (2010–2019) with Charpy V-notch toughness values for the weld seam as low as 1-ft. lbs. that has been used in gas transmission pipelines. Furthermore, API 5L does not contain required minimum Charpy V-notch toughness values for the weld seam.

A single default assumed toughness value might be inappropriate or overly conservative under some circumstances, or it might be a proper choice under other circumstances. To address this issue in this final rule, PHMSA is allowing the use of: (1) Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) from the same vintage and the same steel pipe manufacturers with known properties; (2) a conservative Charpy V-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607; (3) maximum Charpy V-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects if the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects; (4) maximum Charpy V-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion if the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects; or (5) other appropriate Charpy V-notch toughness values that an operator demonstrates can provide conservative Charpy V-notch toughness values for the analysis of the crack-related conditions of the line pipe upon submittal of a notification to PHMSA. These modifications will provide flexibility to operators for considering conservative but realistic estimates of material properties.

PHMSA is also clarifying that operators do not need to use distinct metallurgy and fracture mechanics subject matter experts to review fracture mechanics analyses. In this final rule, PHMSA is replacing that requirement with a general requirement stating that fracture mechanics analyses must be reviewed and confirmed by a qualified subject matter expert. PHMSA expects a qualified subject matter expert to be an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. The operator must be able to document that the individual is appropriately knowledgeable and experienced in the subject being assessed.

B. MAOP Reconfirmation—§ 192.624

v.—Legacy Construction Techniques/ Legacy Pipe

1. Summary of PHMSA's Proposal

PHMSA proposed to add a definition to part 192 for ''legacy construction techniques,'' which defined historical practices used to construct or repair transmission pipeline segments that are no longer recognized as acceptable. In addition, PHMSA proposed a definition for ''legacy pipe'' that is defined by the presence of specific legacy manufacturing, welding, and joining techniques.

2. Summary of Public Comment

AGA expressed significant concerns with the proposed definitions of legacy pipe and legacy construction techniques for the purposes of part 192, commenting that PHMSA should eliminate the use of the terms entirely or otherwise revise these definitions to exclude currently acceptable manufacturing and construction techniques. AGA stated if PHMSA were to codify the definitions of legacy pipe and legacy construction techniques, then PHMSA should limit its catch-all provisions within the language of the definitions to pipes with a longitudinal joint factor of less than 1.0. Doing so would ultimately include pipes with unknown joint factors, as § 192.113 requires a default longitudinal joint factor of 0.80 for any pipe with an unknown longitudinal joint factor. Similarly, AGL Resources, Alliant Energy, Atmos Energy, and TECO Peoples Gas supported AGA's suggested revisions to the definitions of legacy construction techniques and legacy pipe. API commented that PHMSA's proposed definition of legacy construction technique inappropriately includes the repair technique of puddle welds and recommended PHMSA clarify the definitions of wrought iron and pipe made from Bessemer steel. Dominion Transmission commented there may be instances where the longitudinal seam for modern day pipe is unknown, yet the pipe is not a high-risk seam type. They stated that such pipe does not present an integrity threat and should be excluded from the ''legacy pipe'' definition.

Gas Piping Technology Committee commented that the proposed definition of legacy construction techniques seems to contain some erroneous information. They asserted that the proposed definition went too far by implying that all the listed methods are no longer used to construct or repair pipelines, stating that while wrinkle bends may no longer be a common construction technique, they are still allowed under § 192.315 for steel pipe operating at a pressure producing a hoop stress of less than 30 percent of SMYS. Similarly, Oleksa and Associates commented that some operators are still installing Dresser couplings.

The Michigan Public Service Commission staff suggested that PHMSA add to the definition of ''legacy construction techniques'' a subsection that addresses other legacy construction techniques that are not in the current list and include within this subsection language referencing ''all other'' techniques. Northern Natural Gas proposed PHMSA eliminate the phrase ''including any of the following techniques'' from the definition of legacy construction techniques as it implies the list is not complete. They suggested that the definition of legacy pipe should differentiate between ductile and brittle pipe by toughness values in both the seam and the pipe body. Lastly, SoCalGas thought it would be more appropriate to reference these definitions under the IM regulations in subpart O instead of defining the terms in the context of the entire part.

These definitions were taken up by the GPAC in the context of the scope of MAOP reconfirmation, and they recommended in the meeting on March 26, 2018, that the definitions be withdrawn. Because the GPAC recommended to revise the scope of MAOP confirmation to not include pipelines with previous reportable incidents due to crack defects, these definitions would no longer be needed in the rule.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed definitions for ''legacy pipe'' and ''legacy construction techniques.'' After considering these comments and as recommended by the GPAC, PHMSA is withdrawing these definitions from the final rule. Because the revised scope of MAOP confirmation requirements, discussed in the previous sections, no longer includes pipelines with previous reportable incidents due to crack defects, these definitions are no longer necessary.

C. Seismicity and Other Integrity Management Clarifications—§ 192.917

1. Summary of PHMSA's Proposal

Subpart O of 49 CFR part 192 prescribes requirements for managing pipeline integrity in HCAs. It requires operators of covered segments to identify potential threats to pipeline integrity and use that threat identification in their integrity programs. Included within this process are requirements to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment. Special requirements are included to address particular threats such as third-party damage and manufacturing and construction defects.

Following the PG&E incident, the NTSB recommended that PG&E evaluate every aspect of its IM program, paying particular attention to the areas identified in the incident investigation, and implement a revised IM program. PHMSA held a workshop on July 21, 2011, to address perceived shortcomings in the implementation of IM risk assessment processes and the information and data analysis (including records) upon which such risk assessments are based. PHMSA also sought input from stakeholders on these issues in the ANPRM.

Section 29 of the 2011 Pipeline Safety Act requires that operators consider the seismicity of the geographic area in identifying and evaluating all potential threats to each pipeline segment, pursuant to 49 CFR part 192. Pipeline threat analysis is addressed as one program element in the IM regulations in subpart O. Addressing seismicity is already implicitly required by § 192.917 as part of addressing outside force threat through the incorporation by reference of ASME B31.8S. Based on the direction of the mandate, PHMSA proposed to explicitly require that operators analyze seismicity and related geotechnical hazards, such as geology and soil stability, as part of the threat identification IM program element and mitigate those threats of outside force damage. PHMSA determined this would clarify expectations for this requirement and explicitly implement section 29 of the 2011 Pipeline Safety Act.

PHMSA also proposed revisions to § 192.917(e) to clarify that certain pipe designs must be pressure tested to assume that seam flaws are stable and that failures or changes to operating pressures that could affect seam stability are evaluated using fracture mechanics analysis.

2. Summary of Public Comment

There was broad support for explicitly requiring the consideration of the seismicity of a geographic area when identifying and evaluating all potential threats to a pipeline segment, and several stakeholders suggested minor revisions to the proposal. California Public Utilities Commission (CPUC) supported the proposed provisions and recommended adding text that would require consideration of any significant localized threat that could affect the integrity of the pipeline. CPUC further commented that operating conditions on the pipeline must also be a factor when operators identify local threats.

Some commenters, including PG&E and NGA, requested further clarification regarding what would constitute a seismic event for the purposes of identifying threats under the IM program for compliance purposes. AGA requested clarification on the requirements regarding whether operators are expected to conduct a one-time investigation on the risk of seismicity and geology, or if there is an expectation of a periodic requirement for re-investigation.

Multiple commenters disagreed with the proposed requirement in § 192.917(e) for operators to perform annual cyclic fatigue analyses if an operator identifies cyclic fatigue as a threat. INGAA and National Fuel suggested that cyclic fatigue is an uncommon risk for natural gas pipelines and asserted that PHMSA did not provided significant technical justification for this analysis requirement. Some commenters suggested that the proposal to address cyclic fatigue and require pressure tests on seam threats is an overcompensation for the level of risk the threats present. Trade associations and pipeline industries proposed several alternative requirements for the conditions under which cyclic fatigue analyses should be required. API stated that they did not object to the measures listed, but the proposed provisions in § 192.935(b)(2) imply that an operator must take all the actions listed. API asserted that PHMSA should modify this proposed provision to state that operators must consider taking the actions listed but would not be specifically required to take all of them. Other commenters expressed concern that these proposed requirements conflict with the proposed requirements for pipeline segments needing to undertake MAOP reconfirmation because they experienced an incident due to manufacturing and construction (M&C) defects. Specifically, the requirements under § 192.917(e)(3) only allow operators to consider M&C defects stable if they have been subjected to a hydrostatic pressure test of 1.25 times MAOP, which would seemingly disallow or otherwise make fruitless the other methods of MAOP reconfirmation for these types of pipeline segments.

At the GPAC meeting on January 12, 2017, the GPAC recommended that no changes should be made to the proposed provisions on seismicity.

Regarding § 192.917(e)(2), which was discussed during the meeting on June 6–7, 2017, the GPAC noted that, under this provision, operators should be monitoring for condition changes that would cause the threat to potentially activate, and those condition changes should be what triggers a reassessment. The GPAC also noted problems with a suggested revision of performing a cyclic fatigue analysis within a 7-calendar-year period to match certain IM requirements because it would then impose a hard deadline on the continuous monitoring process and would prompt operators to act and again study cyclic fatigue even if the monitoring showed no evidence of cyclic fatigue being a threat. At the meeting, PHMSA suggested that operators could ensure the data involved in a cyclic fatigue analysis is periodically verified within a period not exceeding 7 years to align with IM requirements, but operators would only be required to perform a full evaluation if the data has changed. Following that discussion, the GPAC recommended revising the proposed requirements for cyclic fatigue at § 192.917 based on the discussion of GPAC members and considering PHMSA's proposed language that was presented at the meeting.

At the GPAC meeting on March 26–28, 2018, a public commenter suggested PHMSA remove the word ''hydrostatic'' from the requirements for considering M&C-related defects stable because any strength test that is approved in subpart J should qualify. Further, that public commenter suggested adding language where a pressure reduction or an ILI assessment with an ECA could be allowed for M&C defects as well. Another public commenter suggested removing references to cracks in these sections if PHMSA was intending to create a new section dedicated to addressing crack defects.

Ultimately, the GPAC recommended PHMSA revise the proposed requirements for M&C defects by deleting a cross-reference with the MAOP reconfirmation requirements, updating an applicability reference, and considering removing the term ''hydrostatic'' while allowing other authorized testing procedures. For the requirements related to electric resistance welded (ERW) pipe, the GPAC recommended PHMSA delete the phrase related to pipe body cracking and have those requirements be addressed in a new section within the IM regulations related to crack defects.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the consideration of seismicity and manufacturing- and construction-related defects under the IM regulations. After considering these comments as well as recommendations by the GPAC, PHMSA is revising § 192.917(e)(2) to require operators monitor operating pressure cycles and periodically determine if the cyclic fatigue analysis is valid at least once every 7 calendar years, not to exceed 90 months, as necessary. PHMSA is also deleting a reference to the MAOP reconfirmation requirements in § 192.624 and is referencing the new § 192.712 for fracture mechanics analysis. PHMSA believes these changes are consistent with current IM requirements and will increase regulatory flexibility while maintaining pipeline safety.

In § 192.917(e)(3), PHMSA deleted a cross-reference to the MAOP reconfirmation requirements in § 192.624 and replaced it with a requirement to prioritize the pipeline segment if it has experienced an in-service reportable incident since its most recent successful subpart J pressure test due to an original manufacturing-related defect; or a construction-, installation-, or fabrication-related defect. This clarifies that the IM requirement in § 192.917(e)(3) is not part of the MAOP reconfirmation standards. Although the GPAC asked PHMSA to consider removing the term ''hydrostatic'' and allow other testing procedures, PHMSA is retaining the term ''hydrostatic'' in § 192.917(e)(3), as the proposed revision, as written, addresses NTSB recommendation P–11–15. The NTSB specifically recommended that PHMSA amend part 192 so that manufacturing- and construction-related defects can only be considered stable following a postconstruction hydrostatic pressure test of at least 1.25 times the MAOP. Therefore, deleting the word ''hydrostatic'' would be contrary to the letter and intent of this NTSB recommendation.

For the requirements related to ERW pipe in § 192.917(e)(4), PHMSA has deleted the phrase related to pipe body cracking and deleted a cross-reference to the MAOP reconfirmation requirements in § 192.624, referencing the new § 192.712 for fracture mechanics analysis instead for cracking and crack-related issues. PHMSA made these changes to streamline the regulations and increase readability.

D. 6-Month Grace Period for 7-Calendar-Year Reassessment Intervals—§ 192.939

1. Summary of PHMSA's Proposal

Section 5 of the 2011 Pipeline Safety Act identifies a technical correction amending 49 U.S.C. 60109(c)(3)(B) to allow the Secretary of Transportation to extend the 7-calendar-year IM reassessment interval for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. The NPRM proposed to codify this technical correction as required by the statute.

2. Summary of Public Comment

PHMSA received a comment regarding the 6-month grace period for the 7-calendar-year reassessment interval from a trade organization expressing general support of the proposed provisions and requesting that PHMSA clarify that the 6-month extension begins after the close of the 7-calendar-year reassessment interval period, which would be consistent with the 2011 Pipeline Safety Act revision to the Federal Pipeline Safety Statutes.

At the GPAC meeting on January 12, 2017, the GPAC voted that the proposed changes on the 6-month grace period for the reassessment intervals are technically feasible, reasonable, cost-effective, and practicable, and did not recommend that PHMSA modify these proposed provisions.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the grace period for IM reassessment intervals. After considering the comment and as recommended by the GPAC, PHMSA is retaining the proposed revisions to § 192.939 in this final rule. The proposed rule clearly stated that the 6-month extension begins after the close of the 7-calendar-year reassessment interval period. This is mirrored in PHMSA's frequently asked questions (FAQ) for the IM program,[72] which clarifies that the maximum interval for reassessment may be set using the specified number of calendar years in accordance with the 2011 Pipeline Safety Act. The use of calendar years is specific to gas pipeline reassessment interval years under IM and does not alter the interval requirements that appear elsewhere in the code for various inspection and maintenance requirements.

E. ILI Launcher and Receiver Safety—§ 192.750

1. Summary of PHMSA's Proposal

PHMSA determined that more explicit safety requirements are needed when performing maintenance activities that use launchers and receivers for inserting and removing ILI maintenance tools and devices. The current regulations for hazardous liquid pipelines under part 195 have, since 1981, contained safety requirements for scraper and sphere facilities. However, the current regulations for natural gas transmission pipelines do not similarly require controls or instrumentation to protect against an inadvertent breach of system integrity due to the incorrect operation of launchers and receivers for ILI tools, or scraper and sphere facilities. As a result, PHMSA proposed to add a new section to the Federal Pipeline Safety Regulations to require ILI launchers and receivers include a suitable means to relieve pressure in the barrel and either a means to indicate the pressure in the barrel or a means to prevent opening if pressure has not been relieved. While most launchers and receivers are already equipped with such devices, some older facilities may not be so equipped. Under the proposed provisions, operators would be required to have this safety equipment installed consistent with current industry practice.

2. Summary of Public Comment

Stakeholders, including TPA, provided input on PHMSA's changes to the requirements for safety when performing maintenance activities that utilize launchers and receivers for inserting and removing inspection and maintenance tools and devices. TPA supported the proposed safety additions to the regulations but stated that § 192.750 should be included within the regulations for pipeline components rather than the subpart for pipeline maintenance. In addition, TPA suggested PHMSA revise the language to allow 18 months after the effective date of the rule to comply with the provisions. This change would allow for more time to plan, budget, and complete the work safely. Another commenter recommended these provisions be effective prior to the next time an operator would use an applicable launcher or receiver. Public interest groups and others, such as PST and NAPSR, had broad support for the proposed provisions regarding ILI launcher and receiver safety.

At the GPAC meeting on January 12, 2017, a public commenter suggested clarification on PHMSA's use of the term ''relief device'' or ''relief valve'' within the proposed provisions. During discussion, the committee noted that there are requirements for ''relief valves'' elsewhere in the code, and calling a needed safety device for ILI launchers and receivers a ''relief valve'' would then make it subject to those additional requirements. Based on that discussion, the committee recommended that PHMSA modify the proposed rule to clarify that the rule does not require ''relief valves'' or use ''relief valve'' as an officially defined term within the provision, as those terms have distinct meanings within the broader context of the Federal Pipeline Safety Regulations.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding launcher and receiver safety. After considering these comments and the GPAC input, PHMSA is finalizing the provisions as they were proposed in the NPRM, with the exception of a compliance date 1 year after the effective date of the rule. This approach avoids disruption of work planned within a year of the effective date of the rule, and it allows operators that are not planning work until beyond the 1-year grace period to implement the upgrade before the next planned use. Therefore, special modification work would not be required before the launcher or receiver is needed. Operators would not be required to perform the upgrades until the launcher or receiver is to be used.

Consistent with the originally proposed language, this final rule does not use the term ''relief valve'' and instead uses the generic phrase ''device capable of safely relieving pressure.'' The proposed rule effectively avoided any potential for confusion with respect to the defined term ''relief valve'' and the requirements associated with those components, therefore no change to this wording was necessary for this final rule.

PHMSA believes that this requirement is appropriately located in subpart M, ''Maintenance,'' of part 192, and notes that the comparable requirement in part 195 for hazardous liquid pipelines is located in subpart F, ''Operations and Maintenance.''

F. MAOP Exceedance Reporting—§§ 191.23, 191.25

1. Summary of PHMSA's Proposal

Section 23 of the 2011 Pipeline Safety Act requires that operators report each exceedance of a pipeline's MAOP beyond the build-up allowed for the operation of pressure-limiting or control devices. On December 21, 2012 (77 FR 75699), PHMSA published Advisory Bulletin ADB–2012–11 to advise operators of their responsibility under section 23 of the 2011 Pipeline Safety Act to report such exceedances. The advisory bulletin further stated that the reporting requirement is applicable to all gas transmission pipeline facility owners and operators. PHMSA advised pipeline owners and operators to submit this information in the same manner as safety-related condition reports. The information pipeline owners and operators submit should comport with the information listed at § 191.25(b), and pipeline owners and operators submitting such information should use the reporting methods listed at § 191.25(a).

Although this provision of the 2011 Pipeline Safety Act is self-executing, PHMSA proposed to revise the safety-related condition reporting requirements under part 191 to codify this requirement and harmonize part 191 with the statutory requirement by eliminating the reporting exemption and to provide a consistent procedure,

[72] FAQ–41 at *https://primis.phmsa.dot.gov/gasimp/faqs.htm.*

format, and structure for operators to submit such reports.

2. Summary of Public Comment

Trade associations, citizen groups, and pipeline industries generally supported PHMSA's codification of the statutory reporting requirements for MAOP exceedances for transmission lines.

API and GPA objected to MAOP exceedance reporting requirements for unregulated gathering pipelines. GPA stated that PHMSA did not sufficiently weigh the benefits of reporting MAOP exceedance against the hurdles to compliance for unregulated gathering pipelines. GPA also questioned whether PHMSA has the authority to require unregulated gathering pipelines report MAOP exceedance, since complying with this reporting requirement would necessitate that unregulated gathering pipelines establish MAOP, which they are currently not required to do. Citizen and other safety groups, including Earthworks, NAPSR, the Pipeline Safety Coalition, and PST, supported the inclusion of unregulated gathering pipelines in this section, stating that it would improve pipeline safety.

Several commenters suggested editorial revisions to streamline and improve these provisions. NGA expressed concern that the proposed provisions could apply to distribution systems and suggested that PHMSA clarify that reporting requirements for MAOP exceedance only apply to transmission pipelines. Additionally, Spectra Energy Partners requested that PHMSA require reporting of MAOP exceedances only when the operator is unable to respond to MAOP exceedances within the timeframe required elsewhere in part 192.

One operator expressed concern that the proposed change would require operators to submit additional safety-related condition reports anytime the operator had to implement a pressure reduction upon discovering an immediate condition.

At the GPAC meeting on June 7, 2017, there was brief discussion on whether the 5-day reporting requirement was too prescriptive, but the committee agreed that PHMSA was properly implementing the statutory requirement as written and intended by Congress. Following that discussion, the committee recommended that PHMSA modify the proposed rule to clarify that the MAOP exceedance reporting provisions do not apply to gathering lines.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding MAOP exceedance reporting. The 2011 Pipeline Safety Act mandates that an operator report MAOP exceedances on gas transmission lines, regardless of whether the operator corrects the safety-related condition through repair or replacement. After considering the comments PHMSA received on the NPRM and as recommended by the GPAC, PHMSA is inserting the word "only" in the additional MAOP exceedance reporting provision in § 191.23(a)(10) to make it clearer that the amended requirement applies only to gas transmission lines and not to gathering or distribution lines. Conforming changes were made to § 191.23(a)(6). PHMSA notes that the prior safety-related condition reporting requirements and exceptions related to pressure exceedances for gathering and distribution lines have not been altered.

G. Strengthening Assessment Requirements—§§ 192.150, 192.493, 192.921, 192.937, Appendix F

i. Industry Standards for ILI—§§ 192.150, 192.493

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to revise § 192.150 to incorporate by reference a NACE Standard Practice, NACE SP0102–2010, "In-line Inspection of Pipelines," to promote a higher level of safety by establishing consistent standards for the design and construction of pipelines to accommodate ILI devices.

In § 192.493, PHMSA proposed requirements for operators to comply with the requirements and recommendations of API STD 1163, In-line Inspection Systems Qualification Standard; ANSI/ASNT ILI–PQ–2005, In-line Inspection Personnel Qualification and Certification; and NACE SP0102–2010, In-line Inspection of Pipelines. PHMSA also proposed to allow operators to conduct assessments using tethered or remotely controlled tools.

2. Summary of Public Comment

NAPSR supported the proposed provisions in § 192.493, commenting that the incorporation by reference of the three consensus standards provides enhanced guidance for the determination of adequate procedures and qualifications related to in-line inspections of transmission pipelines.

Some industry representatives commented that it is unnecessary to incorporate American Society for Nondestructive Testing (ASNT) ILI–PQ by reference since API 1163 requires that providers of ILI services ensure that their employees are qualified. Others commented that PHMSA should exclude requirements contained in section 11 of API 1163, which pertains to quality management systems. Lastly, industry representatives asserted that ILI vendors may not be able to meet the 90 percent tool tolerance specified in the referenced standards, and PHMSA should relocate these proposed requirements to a different subpart.

Several commenters noted that if PHMSA required compliance with "the requirements and recommendations of" the recommended practices and standards, it would create enforceable requirements out of actions that the standards themselves did not necessarily mandate.

During the GPAC meeting of March 2, 2018, the committee recommended PHMSA revise this provision by striking the phrase "the requirements and the recommendations of," so that recommendations within the incorporated standard would not be made mandatory requirements.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the incorporation by reference of industry standards for ILI. After considering these comments and as recommended by the GPAC, PHMSA is deleting the phrase "the requirements and the recommendations of" from §§ 192.150 and 192.493 so that the recommendations within the incorporated standard would not be made mandatory requirements.

PHMSA believes that the inclusion of the NACE standard at § 192.150 will help to address the NTSB recommendation P–15–20, which asked PHMSA to identify all operational complications that limit the use of ILI tools in piggable pipelines, develop methods to eliminate those complications, and require operators use such methods to increase the use of ILI tools. PHMSA also believes that more pipelines will become piggable in the future as the nation's pipeline infrastructure ages and is eventually replaced. A current provision in the regulations requires that all new and replaced pipeline be piggable, and as operators address higher-risk infrastructure through this rulemaking, there is a likelihood that some previously unpiggable pipe will be replaced.

PHMSA disagrees that ASNT ILI–PQ is unnecessary. The foreword of API 1163 states "*This standard serves as an umbrella document to be used with and complement companion standards.*

NACE SP0102, In-line Inspection of Pipelines and ASNT ILI–PQ, In-line Inspection Personnel Qualification and Certification.'' These three standards are complimentary and are intended to be used together. PHMSA also disagrees that quality requirements should be excluded from the rule. One of the fundamental objectives of this rule is to establish a minimum standard for quality in conducting ILI. Also, the consensus industry standard API 1163 only uses 90 percent tool tolerance as an example to illustrate key points but does not specify or establish a minimum standard tool tolerance of 90 percent.

G. Strengthening Assessment Requirements—§§ 192.150, 192.493, 192.921, 192.937, Appendix F

ii. Expand Assessment Methods Allowed for IM—§§ 192.921(a) and 192.937(c)

1. Summary of PHMSA's Proposal

In the current Federal Pipeline Safety Regulations, § 192.921 requires that operators with pipelines subject to the IM rules must perform integrity assessments. Currently, operators can assess their pipelines using ILI, pressure test, direct assessment, and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline.

In the NPRM, PHMSA proposed to require that direct assessment only be allowed when the pipeline cannot be assessed using ILI. As a practical matter, direct assessment is typically not chosen as the assessment method if the pipeline can be assessed using ILI. Further, PHMSA proposed to add three additional assessment methods to the regulations:

1. A spike hydrostatic pressure test, which is particularly well-suited to address stress corrosion cracking and other cracking or crack-like defects;
2. Guided Wave Ultrasonic Testing (GWUT), which is particularly appropriate in cases where short segments such as road or railroad crossings are difficult to assess; and
3. Excavation with direct *in situ* examination.

2. Summary of Public Comment

NAPSR expressed its support for the proposed provisions. Many comments expressed concerns with the proposed provisions for the assessment methods regarding uncertainties in reported results. Multiple commenters stated that operators should be able to run the appropriate assessment or ILI tools for the threats that are known or likely to exist on the pipeline based on its condition. Atmos Energy commented that ASME/ANSI B318.S requirements should be the standard to which operators are required to follow. Enable Midstream Partners proposed that PHMSA add ''significant'' to make a distinction between significant and insignificant threats and offered specific language to address its concerns. PG&E commented on the proposed provisions for ILI assessments, requesting that PHMSA provide guidance as to how to explicitly consider the numerous uncertainties associated with ILI regarding anomaly location accuracy, detection thresholds, and sizing accuracy, and suggested that PHMSA allow industry guidance and best practices to be used where practical. Some commenters expressed concern that PHMSA proposed to add requirements surrounding the detection of anomalies that many ILI tools could not meet. These commenters stated that there are no tools designed to find girth weld cracks and that most incidents caused by girth weld cracks have third-party excavation damage as a contributing factor. Commenters further stated that this is a threat that is best handled by procedures that require caution around girth welds during excavation and backfilling procedures.

Several entities commented on the proposed qualification requirements under the ILI assessment method provisions, expressing concern that they are redundant with existing operator qualification regulations under the IM regulations at § 192.915 and the proposed revisions to § 192.493 incorporating the industry ANSI standard on ILI personnel qualification. Multiple entities proposed changes to remove such redundancies and improve clarity.

Commenters requested clarification that the proposed text in the IM assessment provisions ''apply one or more of the following methods for each threat to which the covered segment is susceptible'' does not mean that at least one assessment is required for each threat. Additionally, commenters disagreed with adding an explicit requirement for a ''no objection'' letter as notification of using ''other technology'' and suggested that if this notification is required, operators should be allowed to proceed with the technology if they do not receive a ''no objection'' letter from PHMSA within a certain period.

The NTSB commented that PHMSA's proposal to revise the pipeline inspection requirements to allow the direct assessment method to be used only if a line is not capable of inspection by internal inspection tools directly conflicts with the recommendations of their pipeline safety study, *Integrity Management of Gas Transmission Lines in High Consequence Areas,* which recommended that PHMSA develop and implement a plan for eliminating the use of direct assessment as the sole integrity assessment method for gas transmission pipelines. The CPUC asserted that direct assessment must always be supplemented with other methods, such as ILI or a pressure test.

Many industry entities argued that PHMSA's proposed changes to the IM assessment provisions limiting direct assessment to unpiggable lines are not technically justified. Several entities, including AGA and API, believed it was unreasonable to limit operators' ability to use direct assessment for pipeline assessments unless all other assessment methods have been determined unfeasible or impractical. PG&E requested that PHMSA recognize that although a pipeline may be considered piggable, it does not mean that ILI technology is available, and they provided specific suggestions for revision. Similarly, AGA stated that free-swimming flow-driven ILI tools are often not compatible with intrastate transmission lines for several reasons, stating that certain conditions must exist to assess a pipeline by ILI and obtain valid data, including adequate flow rate, lack of bends or valves that would impede diameter, and ability to insert and remove the tool from the system. Therefore, AGA provided a suggested definition for ''able to accommodate inspection by means of an instrumented in-line inspection tool.''

Trade associations asserted that direct assessment is a proven assessment technique that works in addressing the threat of corrosion. INGAA stated that the criteria for when direct assessment can be used should depend on whether direct assessment can provide the necessary information about the pipe condition rather than whether other assessment methods can be used. AGA commented that it is not aware of any industry study that would suggest that direct assessment does not work effectively to identify corrosion defects in certain circumstances, which it describes in its comments. In addition, AGA stated that direct assessment is a predictive tool that identifies areas where corrosion could occur, including time-dependent threats, while other methods can only detect where corrosion has resulted in a measurable metal loss. Atmos Energy commented that limiting the use of direct assessment only to those pipeline segments that are not capable of inspection by internal inspection tools is not consistent with other requirements of subpart O.

At the GPAC meeting on December 15, 2017, the committee voted to revise the ''no objection'' process to incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. Additionally, the GPAC, during the meeting on March 2, 2018, recommended that PHMSA change these provisions to clarify that operators should select the appropriate assessment based on the threats to which the pipeline is susceptible and remove certain language that is duplicative to another existing section of the regulations. The GPAC also recommended that PHMSA clarify that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable. Further, the GPAC wanted PHMSA to incorporate the notification and objection procedure and 90-day timeframe that the GPAC approved under the material properties verification requirements.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the inclusion of additional assessment methods for integrity assessments. After considering these comments and as recommended by the GPAC, PHMSA is clarifying in this final rule that operators should select the appropriate assessment method based on the threats to which the pipeline is susceptible and is removing language regarding the qualification of persons reviewing ILI results that is duplicative with existing § 192.915. PHMSA is also clarifying in § 192.921 that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable, such as assessing pipe seam threats. In addition, PHMSA incorporated the notification procedure under § 192.18 with the 90-day timeframe and objection process.

PHMSA notes that other comments regarding the determination of suitable assessment methods for applicable threats and ILI tool capabilities relate to long-standing IM regulations that were not proposed for revision. PHMSA did provide substantial additional guidance and standards for implementing the integrity assessment requirements for ILI by incorporating the industry standards in § 192.493, as discussed in the previous sections.

G. Strengthening Assessment Requirements—§§ 192.150, 192.493, 192.921, 192.937, Appendix F

iii. Guided Wave Ultrasonic Testing—Appendix F

1. Summary of PHMSA's Proposal

When expanding assessment methods for both HCA and non-HCA areas, PHMSA proposed to add three additional assessment methods, one being GWUT. Under the existing regulations, GWUT is considered ''other technology,'' and operators must notify PHMSA prior to its use. PHMSA developed guidelines for the use of GWUT, which have proven successful, and proposed to add them under a new Appendix F to part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing. As such, future notifications to PHMSA would not be required, representing a cost savings for operators.

2. Summary of Public Comment

Multiple entities commented in support of using GWUT and the inclusion of proposed Appendix F. NAPSR expressed its agreement with and support for the proposed Appendix. American Public Gas Association (APGA) applauded PHMSA for including guidelines for GWUT; however, it cautioned that the guidance only specifies Guided Ultrasonics LTD (GUL) Wavemaker G3 and G4, which use piezoelectric transducer technology, as acceptable technology. APGA recommended that Magnetostrictive Sensor technology also be included as an acceptable guided wave technology, stating that at least one of its members reported good results using this technology for guided wave assessment of an unpiggable segment of a transmission pipeline.

A commenter noted that the requirement of both torsional and longitudinal wave modes in all situations introduces unnecessary complexity into the GWUT data interpretation process. The commenter further noted that PHMSA should specify that torsional wave mode is the primary wave mode when utilizing GWUT, and that longitudinal wave mode may be used as an optional, secondary mode. Other commenters recommended additional changes to Appendix F, such as stating that qualified GWUT equipment operators are trained to understand the strengths, weaknesses, and proper applications of each wave mode and should have the freedom to select the appropriate and most effective wave mode(s) for the given situation. PG&E requested that PHMSA recognize that this technology is used at locations other than casings as implied in the introductory paragraph and commented that double-ended inspections are not always required to meet the specification.

During the GPAC meeting on December 15, 2017, the GPAC agreed with the provisions related to Appendix F and GWUT but recommended PHMSA revise the ''no objection'' letter process.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding GWUT. After considering these comments and as recommended by the GPAC, PHMSA is removing the reference to GUL equipment for clarity. PHMSA is modifying the notification process to allow operators to proceed with an alternative process for using GWUT if the operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA in accordance with § 192.18. PHMSA believes this change increases regulatory flexibility while maintaining pipeline safety.

In this final rule, PHMSA is retaining the requirement to use both torsional and longitudinal wave modes since that is a long-standing requirement in PHMSA's guidance for accepting GWUT as an allowed technology under an ''other technology'' notification. Also, PHMSA recognizes that GWUT is used at locations other than casings, although it is most often deployed for the integrity assessment of cased crossings. However, double-ended inspections would not always be required to meet Appendix F, and Appendix F does not require double-ended inspections. Double-ended inspections are not necessary as long as the guided wave ultrasonic test covers the entire length of the assessment as well as the ''dead zone'' where the equipment is set up.

The proposed rule already addresses validation of operator training, but in this final rule, PHMSA is deleting the sentence ''[t]here is no industry standard for qualifying GWUT service providers'' to provide clarity.

H. Assessing Areas Outside of HCAs—§§ 192.3, 192.710

i. MCA Definition—§ 192.3

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA introduced a new definition for a Moderate Consequence Area (MCA). The proposed rule defined an MCA as an onshore area, not meeting the definition of an HCA, that is within a potential impact circle, as defined in § 192.903, containing 5 or more buildings intended for human occupancy; an occupied site; or a right-of-way for a designated interstate, freeway, expressway, or other principal four-lane arterial roadway as defined in the Federal Highway Administration's ''Highway Functional Classification Concepts, Criteria and Procedures.'' PHMSA proposed that requirements for data analysis, assessment methods, and immediate repair conditions within these MCAs would be similar to requirements for HCA pipeline segments but with longer timeframes so that operators could properly allocate resources to higher-consequence areas. PHMSA proposed that the 1-year repair conditions that currently exist for HCA pipeline segments would be 2-year repair conditions when found on MCA pipeline segments. These changes would ensure the prompt remediation of anomalous conditions that could potentially affect people, property, or the environment, commensurate with the severity of the defects, while still allowing operators to allocate their resources to HCAs on a higher-priority basis.

2. Summary of Public Comment

The NTSB stated that the proposed provisions to create an MCA category and include a highway size threshold in the definition of an MCA accomplishes part of what the NTSB intended in Safety Recommendation P–14–1. However, the NTSB objected to the proposed highway coverage as being limited to four lanes and stated its support of expanding the highway size threshold as they had specifically recommended in P–14–1. The NTSB asserted that the proposed language would exclude the category of other principal arterial roadways wider than four lanes when, in fact, the wider roadways should be included.

INGAA supported the addition of an MCA category to the Federal Pipeline Safety Regulations but recommended several modifications to the proposed definition. INGAA suggested PHMSA should limit the definition of an MCA to only those pipeline segments that could be assessed through an ILI inspection, amend the MCA definition to avoid ambiguity regarding residential structures, remove ''outside areas and open structures'' from the portion of the definition of MCA related to ''identified sites,'' include timeframes for incorporating changes to existing MCAs, and permit operators to use the edge of the pavement rather than the highway right-of-way to determine if a roadway intersects with a Potential Impact Circle.

AGA, API, APGA, and several pipeline entities agreed with INGAA's comments on the modification to PHMSA's proposed MCA definition. Additionally, AGA, API, and APGA emphasized PHMSA should remove the reference to ''a right-of-way'' for the designated roadways, commenting that the MCA definition could be interpreted so that if a Potential Impact Circle touches any portion of the roadway right-of-way, the pipeline segment is an MCA. That interpretation would put undue burden on operators in areas where its pipelines lay at or near the edge of the public right-of-way that would not normally contain ''persons or property'' that would sustain damage or loss in the event of a pipeline failure. Further, API added that the reference to ''a right-of-way'' is problematic because roadway right-of-ways are variable, cannot be seen with the naked eye, and are often not included in publicly available data sources.

Commenters also disagreed with the definition of ''occupied site'' within the MCA definition. GPA asserted that the criterion used in the MCA definition should be limited to interstate highways, and the definition of ''occupied site'' should be eliminated to more clearly distinguish between MCAs and HCAs and to provide greater clarity in identifying and managing MCAs. Similarly, Enlink Midstream commented that PHMSA should eliminate the definition of occupied site and remove this criterion from the proposed definition of MCA. Doing so would permit the continued focus on HCAs that the IM process was intended to accomplish. AGL Resources also expressed concern with the proposed definition of occupied site, commenting that this definition could require operators to effectively perform a census-like identification of structures to verify the count of persons within that structure.

There were conflicting viewpoints on where the definition of MCA should be placed in the regulations. API and other commenters stated that they preferred a new category and a distinct definition for MCA as opposed to expanding the definition of HCA or making a subcategory in the HCA definition for MCAs, whereas SoCalGas encouraged expanding the scope of HCAs rather than creating a new category.

Enterprise Products commented PHMSA should move the MCA definition to subpart O and remove the ''occupied site'' criteria from the proposed definition of MCA, which would provide more distinction between MCAs and HCAs in the regulations and would also more appropriately place them under the IM regulations.

AGA and several other organizations expressed concern over the resource-intensive administrative task of identifying MCAs, especially pertaining to recordkeeping requirements. API asserted that the proposed provisions would limit operators' ability to prioritize resources for pipelines that pose the highest risk. They further stated that while they agree with the inclusion of all Class 3 and Class 4 locations, occupied sites, and major roadways in the definition of MCA, they disagree with the proposed threshold of five buildings intended for human occupancy within the potential impact radius. They suggested that a more appropriate threshold would be more than 10 buildings intended for human occupancy, as that number is consistent with longstanding part 192 class location designations.

Multiple groups, such as AGI, INGAA, and Cheniere Energy, also stated objections over various aspects of defining and identifying MCAs and provided suggestions for revised language, including several broad clarifications or deletions to the definition. In addition to requesting modifications to the definition of MCA, INGAA objected to the provided geographic information system (GIS) layer for right-of-way determination, and suggested that PHMSA provide one database for roadway classification. Numerous trade associations and pipeline companies asked PHMSA to consider a qualifier that the definition of MCA only applies to pipelines operating at greater than 30 percent SMYS. EnLink Midstream suggested using a threshold level of 16-inch pipe diameter to identify pipelines that pose a greater risk.

The GPAC had a comprehensive discussion on the MCA definition during the meeting on March 2, 2018, and approved of the definition with some changes. First, the GPAC recommended changing the highway description within the definition to remove reference to the roadway ''rights-of-way'' and to add language so that the highway consists of ''any portion of the paved surface, including shoulders.'' Secondly, the GPAC recommended clarifying that highways with 4 or more lanes are included, and they also wanted PHMSA to work together with the Federal Highway Administration to provide operators with clear information relative to this aspect of the rulemaking and discuss it in the preamble. The GPAC also recommended that PHMSA discuss in the preamble what they expect the definition of ''piggable'' to be, as it is critical for aspects of the MCA definition as it relates to MAOP confirmation. Finally, the GPAC recommended PHMSA modify the term ''occupied sites'' in the MCA definition and in the definitions section of part 192 by removing the language referring to ''5 or more persons'' and the timeframe of 50 days and tying the requirement into the HCA survey for ''identified sites'' as discussed by GPAC members and PHMSA at the meeting. The committee noted that such site identification could be made through publicly available databases and class location surveys. The committee suggested PHMSA consider the necessary sites and enforceability of the definition per direction by the committee members.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the definition of moderate consequence area. After considering these comments and the GPAC input, PHMSA is modifying the highway description within the definition to remove reference to the roadway ''rights-of-way'' and to add language so that the highway consists of ''any portion of the paved surface, including shoulders.'' Also, PHMSA is specifying that highways with 4 or more lanes are included. PHMSA believes these changes provide additional clarity.

Per the GPAC's request that PHMSA provide additional guidance on what roadways are included in the MCA definition as it pertains to ''other principal roadways with 4 or more lanes,'' PHMSA notes that the Federal Highway Administration defines *Other Principal Arterial* roadways[73] as those roadways that serve major centers of metropolitan areas, provide a high degree of mobility, and can also provide mobility through rural areas. Unlike their access-controlled counterparts (interstates, freeways, and expressways), abutting land uses can be served directly. Forms of access for *Other Principal Arterial* roadways include driveways to specific parcels and at-grade intersections with other roadways. For the most part, roadways that fall into the top three functional classification categories (Interstate, Other Freeways & Expressways, and Other Principal Arterials) provide similar service in both urban and rural areas. The primary difference is that there are usually multiple arterial routes serving a particular urban area, radiating out from the urban center to serve the surrounding region. In contrast, an expanse of a rural area of equal size would be served by a single arterial. The MCA definition does not include all roadways that meet this definition but instead is limited to those roadways meeting this definition that have four or more lanes.

With respect to ''occupied sites,'' PHMSA evaluated the comments and the GPAC discussion and concluded that including occupied sites within the MCA definition was not necessary. Industry representatives on the GPAC asserted that most locations meeting the definition of occupied site are, as a practical matter, already included as an identified site and designated as an HCA. Commenters suggested most operators find it expedient to declare sites similar to occupied areas as HCAs instead of counting the specific occupancy of such locations to see if they meet the occupancy standard over the course of a year. Operators then monitor occupancy in subsequent years for changes that might change the site's status as an occupied site. Such an approach would require fewer resources and be more conservative from a public safety standpoint. Based on these comments, PHMSA is persuaded that including another category of locations, similar to identified sites in HCAs but with a lower occupancy standard of 5 persons, is unnecessarily burdensome without a comparable decrease in risk.

PHMSA disagrees that the MCA definition should be moved to subpart O. The term is used in sections outside of subpart O. Including the MCA definition in § 192.3 is necessary for it to apply to the sections in which it is used throughout part 192.

H. Assessing Areas Outside of HCAs—§§ 192.3, 192.710

ii. Non-HCA Assessments—§ 192.710

1. Summary of PHMSA's Proposal

PHMSA proposed to add a new § 192.710 to require that pipeline segments in Class 3 or Class 4 locations, and piggable segments in MCAs, be initially assessed within 15 years and no later than every 20 years thereafter on a recurring basis. PHMSA also proposed to require assessments in these areas be conducted using the same methods that are currently allowed for HCAs. PHMSA has found that operators have assessed significant non-HCA pipeline mileage in conjunction with performing HCA integrity assessments in the same pipeline. Therefore, PHMSA proposed to allow the use of those prior assessments of non-HCA pipeline segments to comply with the new § 192.710.

In effect, to this limited population of pipeline segments outside of HCAs, PHMSA proposed to expand the applicability of IM program elements related to baseline integrity assessments, remediating conditions found during integrity assessments, and periodic reassessments. In addition, under the proposed provisions, MCAs would be subject to other requirements related to the congressional mandates, including material properties verification and MAOP reconfirmation. Any assessments an operator would conduct to reconfirm MAOP under proposed § 192.624 would count as an initial assessment or re-assessment, as applicable, under the proposed requirements for non-HCA assessments.

2. Summary of Public Comment

The NTSB and multiple citizen groups supported the expansion of IM elements to gas transmission pipelines in areas outside those currently defined as HCAs. However, several entities, including PST, stated that applying a limited suite of IM tools to these areas was insufficient and requested that the full suite of IM elements be applied to the additional pipeline segments. Some citizen groups expressed concern that the 15-year implementation period and 20-year re-inspection period was too long.

While pipeline companies and trade associations generally supported PHMSA's efforts to expand IM elements beyond HCAs, many of them stated concerns over the time and cost required to identify MCAs, the efficacy of the changes, and the language and requirements regarding both the limitation of assessments to pipeline segments accommodating inline inspection tools and (re)assessment periods. Many groups requested a clear, concise set of codified requirements for IM outside of HCAs to simplify identification, recordkeeping, and repairs.

Several commenters provided input on the allowable assessment methods for non-HCAs. AGA suggested that PHMSA create a new subpart consisting of a clear and concise set of codified requirements for the non-HCA assessments, including new definitions regarding the limitation of assessments to pipeline segments accommodating instrumented inline inspection tools. Many trade associations and pipeline companies stated that they thought the direct assessment method could achieve a satisfactory level of inspection in place of costlier in-line inspection,

[73] Federal Highway Administration, Office of Planning, Environment, & Realty (HEP), *Highway Functional Classification Concepts, Criteria and Procedures (2013) https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/section03.cfm#Toc336872980.*

especially given the additional detail added to the in-line inspection assessment method in the proposal. API requested that PHMSA allow operators to rely on any prior assessments performed under subpart O requirements of part 192 in effect at the time of the assessment rather than limit the allowance to ILI. Furthermore, other organizations supported AGA's proposal that mirrors and extends to MCAs the two-methodology approach used to determine HCAs in the existing § 192.903, which allows for identification based on class location or by the pipeline's potential impact radius.

Entities, including API and Atmos Energy, requested clarification regarding assessment periods and reassessment intervals due to the language regarding shorter reassessment intervals ''based on the type [of] anomaly, operational, material and environmental conditions [. . .], or as otherwise necessary.'' Those commenters said that language was vague and subject to varying interpretations, so they suggested revisions to the language for the reassessment intervals. Lastly, AGA suggested that PHMSA define the term ''pipelines that can accommodate inspection by means of an instrumented in-line inspection tool'' used in proposed §§ 192.710 and 192.624, stating that providing the criteria that a pipeline must meet to be able to accommodate an in-line inspection tool would remove uncertainty and inconsistency in determining which pipelines meet PHMSA's proposed qualifier.

The GPAC discussed the provisions related to assessments outside of HCAs during the meeting on March 2, 2018. The GPAC found the provisions to be technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that direct assessment could be used only if appropriate for the threat being assessed and could not be used to assess threats for which direct assessment is not suitable, and removed the provisions related to low-stress assessments. The GPAC also recommended revising the initial assessment and reassessment intervals for applicable pipeline segments from an initial assessment within 15 years of the effective date of the rule and periodic assessments every 20 years thereafter to an initial assessment within 14 years of the effective date of the rule and periodic assessments every 10 years thereafter. The GPAC stated that the prioritization of initial assessments and reassessments should be based on the risk profiles of the pipelines. The GPAC also wanted PHMSA to apply the assessment and reassessment requirements only to pipelines with MAOPs greater than or equal to 30 percent SMYS.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding integrity assessments outside HCAs. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to specify that direct assessment may be used only if appropriate for the threat being assessed and cannot be used to assess threats for which direct assessment is not suitable, such as assessing pipe seam threats. PHMSA made these changes to provide clarity regarding the proper use of direct assessments.

In addition, PHMSA is revising the applicability of § 192.710 to apply only to pipelines with an MAOP of greater than or equal to 30 percent of SMYS. PHMSA made this change because the GPAC recommended it was cost-effective for the provision to only apply to pipe operating above 30% SMYS in Class 3 and 4 locations and because those pipelines present the greatest risk to safety. Because of this modification, PHMSA is withdrawing provisions related to low-stress assessments since they will no longer be applicable.

Based on the comments and recommendations from the GPAC, PHMSA is also modifying the initial assessment deadline and reassessment intervals for applicable pipeline segments to 14 years after the publication date of the rule and every 10 years thereafter, which was reduced from 15 years and 20 years, respectively. PHMSA believes this change increases regulatory flexibility while maintaining pipeline safety. PHMSA is also adding a requirement that the initial assessments must be scheduled using a risk-based prioritization.

PHMSA disagrees with the need to implement a dual approach to MCA identification that would be similar to the ways that HCAs are identified. Subpart O and the IM regulations were first promulgated before pipeline operators had experience with potential impact radius (PIR) techniques, and incorporating an alternative HCA identification method into the original IM regulations using conventional class locations was convenient and appropriate. Pipeline operators now have over 15 years of experience working with the PIR concept; therefore, PHMSA determined using the PIR method for determining MCAs in the definition of MCAs is appropriate. PHMSA also disagrees that a separate subpart would be preferable and is retaining the requirements for MCA assessments in a new § 192.710.

PHMSA believes the requirement to have a shorter reassessment interval is clear and is not modifying that aspect of the rule. PHMSA included a requirement for operators to not automatically default to the maximum reassessment interval but to establish shorter reassessment intervals ''based upon the type anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety'' when appropriate. Operators have been required to perform similar analyses and adjustment of reassessment intervals for HCAs since the inception of the IM regulations in 2003 and should be familiar with this process over 15 years later. PHMSA believes that stating the overarching goal of assuring public safety by evaluating each pipeline and its circumstances and establishing appropriate assessment intervals based on those circumstances provides clear intent and is an appropriate approach.

PHMSA believes that the term ''piggable segment'' is very widely understood in the industry and is not including additional definitions or regulatory language to expand upon this term. PHMSA understands that a pipeline segment might be incapable of accommodating an in-line inspection tool for a number of reasons, including but not limited to short radius pipe bends or fittings, valves (reduced port) that would not allow a tool to pass, telescoping line diameters, and a lack of isolation valves for launchers and receivers. Some unpiggable pipelines can be made piggable with modest modifications, but others cannot be made piggable short of pipe replacement.

PHMSA understands that a pipeline segment is piggable if it can accommodate an instrumented ILI tool without the need for major physical or operational modification, other than the normal operational work required by the process of performing the inline inspection. This normal operational work includes segment pigging for internal cleaning, operational pressure and flow adjustments to achieve proper tool velocity, system setup such as valve positioning, installation of temporary launchers and receivers, and usage of proper launcher and receiver length and setup for ILI tools. In addition, a pipeline segment that is not piggable for a particular threat because of limitations in technology such that an ILI tool is not commercially available, might be piggable for other threats. For example, a pipeline that is unable to accommodate a crack tool might be able to accommodate a conventional MFL or deformation tool, and thus be piggable for those threats. Launcher and receiver lengths are not a reason for a pipeline to be considered unpiggable, since through a minor modification they can be modified to be piggable, and the removal of launchers or receivers from the pipeline segment does not make a pipeline unpiggable either.

I. Miscellaneous Issues

i. Legal Comments

The following section discusses industry comments related to legal and administrative procedure issues with the proposed rule.

Summary of Public Comment

Several commenters asserted that the proposed provisions go beyond PHMSA's statutory authority provided by the 2011 Pipeline Safety Act. Many trade associations and pipeline industry entities stated that PHMSA exceeded the congressional mandates in the proposed provisions by imposing retroactive recordkeeping requirements and retroactive material properties verification requirements. These comments are discussed in more detail in their respective sections above.

Commenters asserted that, in the 2011 Pipeline Safety Act, Congress identified specific factors that PHMSA is required to consider when proposing regulations per the statutory mandates, including whether certain proposed provisions would be economically, technically, and operationally feasible, and that the proposed rule did not adequately address these factors. For example, AGA expressed concerns that PHMSA proposed to adopt NTSB recommendations without independently justifying those provisions based on the specific factors required by Congress or providing the reasoning behind adopting said recommendations.

AGA and INGAA also stated that PHMSA did not adequately consider the impact that the Natural Gas Act of 1968 would have on implementation of the proposed rule. Noting that operators are required to obtain permission from FERC before removing pipelines from service or replacing pipelines, these commenters stated that obtaining permissions could hinder operators from quickly performing required tests and repairs. INGAA and AGA also stated that PHMSA did not consult with FERC and State regulators about implementation timelines for certain provisions, which PHMSA is required to do in accordance with 49 U.S.C. 60139(d)(3) because gas service would be affected by the proposed rule.

PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the statutory authority for the proposed rule. With regard to the comments about imposing retroactive recordkeeping requirements and retroactive material properties verification requirements, PHMSA explained in this document that the final provisions of this rule are prospective and do not create retroactive requirements. This topic is discussed in more detail in the respective sections about recordkeeping and material properties verification.

Pertaining to PHMSA's broader authority, Congress has authorized the Federal regulation of the transportation of gas by pipeline in the Pipeline Safety Laws (49 U.S.C. 60101 *et seq.*) and established the current framework for regulating pipelines transporting gas in the Natural Gas Pipeline Safety Act of 1968, Public Law 90–481. Through these laws, Congress has delegated the DOT the authority to develop, prescribe, and enforce minimum Federal safety standards for the transportation of gas, including natural gas, flammable gas, or toxic or corrosive gas, by pipeline. As required by law, PHMSA has considered whether the provisions of this rule are economically, technically, and operationally feasible and has provided relevant analysis in the Regulatory Impact Analysis and preamble of this rule.

In accordance with section 23 of the 2011 Pipeline Safety Act, PHMSA consulted with the Federal Energy Regulatory Commission and State regulators as appropriate to establish the timeframes for completing MAOP reconfirmation. As a part of this consultation, PHMSA accounted for potential consequences to public safety and the environment while also accounting for minimal costs and service disruptions. Furthermore, PHMSA will note that both a FERC member and a NAPSR member are on the GPAC, providing both input and positive votes that the provisions were technically feasible, reasonable, cost-effective, and practicable if certain changes were made. As previously discussed, PHMSA has taken the GPAC's input into consideration when drafting this final rule and made the according changes to the provisions.

I. Miscellaneous Issues

ii.—Records

1. Summary of PHMSA's Proposal

Many pipeline records are necessary for the correct setting and validation of MAOP, which is critically important for providing an appropriate margin of safety to the public. Much of operator and PHMSA data is obtained through testing and inspection under the existing IM requirements. Section 192.917(b) requires operators to gather pipeline attribute data as listed in ASME/ANSI B31.8S—2004 Edition, section 4, table 1. ASME/ANSI B31.8S—2004 Edition, section 4.1 states:

''*Pipeline operator procedures, operation and maintenance plans, incident information, and other pipeline operator documents specify and require collection of data that are suitable for integrity/risk assessment. Integration of the data elements is essential in order to obtain complete and accurate information needed for an integrity management program. Implementation of the integrity management program will drive the collection and prioritization of additional data elements required to more fully understand and prevent/mitigate pipeline threats.*''

However, despite this requirement, there continue to be data gaps that make it hard to fully understand the risks to and the integrity of the nation's pipeline system. Therefore, PHMSA proposed amendments to the records requirements for part 192, specifically under the general recordkeeping requirements, class location determination records, material mechanical property records, pipe design records, pipeline component records, welder qualification records, and the MAOP reconfirmation provisions.

2. Summary of Public Comment

Several commenters provided input on the proposed amendments to the records requirements for part 192. Several public interest groups, including Pipeline Safety Coalition and PST, supported the increased emphasis on recordkeeping requirements, stating that the requirements are a proactive response to NTSB recommendations and are common-sense business best practices.

Several commenters opposed the proposed provisions providing general recordkeeping requirements for part 192. Commenters asserted that these proposed provisions apply significant new recordkeeping requirements on operators by requiring that operators document every aspect of part 192 to a higher and impractical standard than before. Commenters also stated that the proposed recordkeeping requirements appear to be retroactive and stated that it would be inappropriate to require operators to document compliance in cases where there have not been requirements to document or retain records in the past. Commenters also asserted that the Pipeline Safety Laws at 49 U.S.C. 60104(b) prohibits PHMSA from applying new safety standards pertaining to design, installation, construction, initial inspection, and initial testing to pipeline facilities already existing when the standard is adopted, and that PHMSA does not have the authority to apply these requirements retroactively. These commenters suggested that even the recordkeeping requirements in these non-retroactive subparts could not be changed under PHMSA's current authority. Subsequently, commenters requested that PHMSA confirm that the proposed general, material, pipe design, and pipeline component recordkeeping requirements would not apply to existing pipelines and that recordkeeping requirements for the qualification of welders and qualifying plastic pipe joint-makers would not apply to completed pipeline projects.

Additionally, several commenters also requested that PHMSA clarify that many of the proposed recordkeeping requirements apply only to gas transmission lines. AGA also expressed concern regarding the proposed reference to material properties verification requirements in the proposed general recordkeeping requirements, which, as written, would also require distribution pipelines without documentation to comply with the proposed material properties verification requirements.

Many commenters opposed the proposed application of the term ''reliable, traceable, verifiable, and complete'' in part 192 beyond the requirements for MAOP records, and AGA recommended the deletion of ''reliable, traceable, verifiable and complete'' from proposed provisions under MAOP reconfirmation. Similarly, other commenters, including INGAA, recommended omitting ''reliable'' from the phrase and provided a suggested definition for ''traceable, verifiable, and complete'' records. Additionally, commenters opposed the use of this term in the general recordkeeping requirements at § 192.13, stating that it would apply a new standard of documentation to part 192. Citing a 2012 PHMSA Advisory Bulletin in which PHMSA stated that verifiable records are those ''in which information is confirmed by other complementary, but separate, documentation,'' INGAA requested that PHMSA acknowledge that a stand-alone record will suffice and a complementary record is only necessary for cases in which the operator is missing an element of a traceable or complete record.[74] INGAA also provided examples of records that they believed to be acceptable, and requested that PHMSA includes these examples in the final preamble.

Several commenters also opposed the proposed Appendix A to part 192 that summarizes the records requirements within part 192 and requested that it be eliminated, stating that Appendix A goes beyond summarizing the existing records requirements and introduces several new recordkeeping requirements and retention times. Commenters also asserted that Appendix A should not be retroactive. Some commenters supported the inclusion of Appendix A, saying that it is a much-needed clarification of record requirements and retention. Noting that the title of Appendix A suggests that it is specific to gas transmission lines but that it does include some record retention intervals for distribution lines, NAPSR recommended that Appendix A be expanded to include records and retention intervals for all types of pipelines. Many commenters requested that PHMSA clarify that the proposed changes to Appendix A apply only to gas transmission lines.

Some commenters also opposed the newly proposed recordkeeping requirements for pipeline components at § 192.205. Commenters, including Dominion East Ohio, stated that PHMSA should exclude pipeline components less than 2 inches in diameter, as these small components are often purchased in bulk with pressure ratings and manufacturing specifications only printed on the component or box. They further stated that in doing this, PHMSA would be consistent with its proposed material properties verification requirements. Another commenter stated that these requirements should be eliminated because they are duplicative of the current requirements for establishing and documenting MAOP at § 192.619(a)(1).

Some commenters also opposed the proposed recordkeeping requirements regarding qualifications of welders and welding operators and qualifying persons to make joints in §§ 192.227 and 192.285, stating that keeping these records for the life of the pipeline is not needed, nor are they necessary for the establishment of MAOP.

Issues related to records were discussed during all of the GPAC meetings in various capacities. At the meeting in January 2017, several issues were discussed, including: broad records guidance in a general duties clause might be a good idea in theory but might cause unintended consequences, and they discussed the advisability of addressing necessary record components individually in the context of specific code sections.

The GPAC discussed the proposed addition of ''reliable'' to the phrase ''traceable, verifiable, and complete'' (TVC) record in the proposed rule. The ''TVC'' standard was recommended by the NTSB following the PG&E incident. Changing that standard could potentially derail work being done by operators to meet that traceable, verifiable, and complete record standard.

The GPAC also discussed PHMSA's statutory authority to impose the proposed recordkeeping requirements, even in subparts that are retroactive, because PHMSA is not requiring particular types of design, installation, construction, etc., but is requiring that operators keep records relevant to current operation.

At the GPAC meeting on June 6, 2017, the GPAC discussed the proposed recordkeeping requirements for the qualification of welders and welding operators as well as the qualification of persons making joints on plastic pipe systems. Specifically, the discussion revolved around whether the recordkeeping requirements should be for the life of the pipeline, as proposed in the NPRM, or whether it should be for 5 years. Certain members believed it should be a 5-year requirement to be consistent with other operator qualification requirements, and other members believed that a 5-year requirement would be adequate due to the ''bathtub curve'' phenomenon where pipelines are more likely to fail early or late in their service history. Therefore, having the records for welding qualification within that early period would be sufficient.

Following that discussion, the committee recommended that PHMSA modify the proposed rule to delete the word ''reliable'' from the records standard to now read ''traceable, verifiable, and complete'' wherever that standard is used; clarify that documentation be required to substantiate the current class location under § 192.5(d); and modify the recordkeeping provisions related to the

[74] *https://www.phmsa.dot.gov/regulations-fr/notices/2012-10866*; 77 FR 26822; May 7, 2012, ''Pipeline Safety: Verification of Records.''

qualification of welders and the qualification of persons joining plastic pipe to include an effective date and change the retention period of the necessary records to 5 years.

At the March 2, 2018, meeting, the GPAC recommended that PHMSA withdraw the general duty recordkeeping requirement at § 192.13(e) and Appendix A; modify the recordkeeping requirements for pipeline components to clarify they apply to components greater than 2 inches in nominal diameter; and revise the requirements related to material, pipe design, and pipeline component records to clarify the effective date of the requirements.

At the meeting on March 27, 2018, the GPAC recommended that PHMSA provide guidance in the preamble regarding what constitutes a traceable, verifiable, and complete record. Further, the GPAC recommended PHMSA clarify that the MAOP recordkeeping requirements in the MAOP establishment section at § 192.619(f) apply only to onshore, steel, gas transmission pipelines, and that they only apply to the records needed to demonstrate compliance with paragraphs (a) through (d) of the section. The GPAC suggested PHMSA could remove examples of acceptable MAOP documents from the rule and include that listing in the preamble of the final rule and through guidance materials.

The GPAC also recommended that PHMSA clarify that the MAOP recordkeeping requirements are not retroactive, that existing records on pipelines installed prior to the rule must be retained for the life of the pipeline, that pipelines constructed after the effective date of the rule must make and retain the appropriate records for the life of the pipeline, and that MAOP records would be required for any pipeline placed into service after the effective date of the rule. Further, the GPAC recommended PHMSA revise the rule by changing other sections, including §§ 192.624 and 192.917, to require when and for which pipeline segments missing MAOP records would need to be verified in accordance with the MAOP reconfirmation and material properties verification requirements of the rulemaking.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed records requirements. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to withdraw the proposed § 192.13(e) and Appendix A to avoid possible confusion regarding recordkeeping requirements. Also, whenever new recordkeeping requirements are included, PHMSA modified the rule to clarify that the new requirements are not retroactive. To the degree that operators already have such records, they must retain them. Operators must retain records created while performing future activities required by the code.

In addition to these general modifications, with regard to specific records requirements, PHMSA is modifying the rule as follows: (1) In § 192.5(d), operators must retain records documenting the current class location (but not historical class locations that no longer apply because PHMSA agrees they are not necessary). (2) In § 192.67, the rule is being modified to delete reference to ''original steel pipe manufacturing records'' to avoid retroactivity concerns, add wall thickness and seam type to clarify that this manufacturing information must be recorded, and include an effective date to eliminate retroactivity concerns. (3) In § 192.205, records for components are only required for components greater than 2 inches (instead of greater than or equal to 2 inches) (see Section III(A)(i)(3)). (4) In § 192.227, records demonstrating each individual welder qualification must be retained for a minimum of 5 years because PHMSA believes 5 years of welder qualification records are sufficient to evaluate whether systemic issues are present upon inspection and at the start-up of the pipeline. (5) In § 192.285, records demonstrating plastic pipe joining qualifications at the time of pipeline installation in accordance must be retained for a minimum of 5 years because PHMSA believes 5 years of records are sufficient to evaluate whether systemic issues are present upon inspection and at the start-up of the pipeline. (6) In § 192.619, PHMSA clarified that new recordkeeping for MAOP only apply to onshore, steel, gas transmission pipelines. In addition, PHMSA deleted the sentence with examples of records that establish the pipeline MAOP, which include, but are not limited to, design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data to prevent redundancies in the regulations as this list is maintained in § 192.607.

PHMSA notes that the recordkeeping requirements in this final rule under §§ 192.67, 192.127, 192.205, and 192.227(c) applicable to gas transmission pipelines will apply to offshore gathering pipelines and Type A gathering pipelines as well. In accordance with this final rule's requirements, operators of such pipelines must keep any of the pertinent records they have upon this rule's issuance, and they must retain any records made when complying with these requirements following the publication of this rule. PHMSA notes that the requirements for creating records in §§ 192.67, 192.127, 192.205, and 192.227(c) are forward-looking requirements. However, and in accordance with this final rule, operators must retain any records they currently have for their pipelines. Any records generated through the course of operation, including, most notably, records generated by the material properties verification process at § 192.607, must also be retained by operators for the life of the pipeline.

As requested by the GPAC, PHMSA considered moving § 192.619(e) to be a subsection of § 192.619(a) and considered referencing § 192.624 in § 192.619(a). However, PHMSA is retaining the proposed paragraph (e) in the final rule and the reference to § 192.624 within § 192.619(e) because it more clearly requires pipeline segments that meet any of the applicability criteria in § 192.624(a) must reconfirm MAOP in accordance with § 192.624, even if they comply with § 192.619(a) through (d). This also avoids the potential for conflict if this requirement were to be placed in a paragraph that applies to gathering lines and distribution lines. It also makes it clear that pipeline segments with MAOP reconfirmed under § 192.624 are not required to comply with § 192.619(a) through (d).

Lastly, throughout this final rule, PHMSA is deleting the word ''reliable'' from the records standard to now read ''traceable, verifiable, and complete'' wherever that description is used. PHMSA issued advisory bulletins ADB 12–06 on May 7, 2012 (77 FR 26822) and ADB 11–01 on January 10, 2011 (76 FR 1504). In these advisory bulletins, PHMSA provided clarification and guidance that all documents are not records and provided additional information on the definition and standard for records. For a document to be a record, it must be traceable, verifiable, and complete. PHMSA provides further explanation of these concepts below.

Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, which include mechanical and chemical properties; purchase requisition; or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.

Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a pipeline segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipeline segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by a qualified individual who observed the test or inspection being performed.

Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking such as a corporate stamp or seal. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipeline segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.

For example, a mill test report must be traceable, verifiable, and complete, which is a typical record for pipelines. For the mill test report to be traceable it would need to be dated in the same time frame as construction or have some other link relating the mill record to the material installed in the pipeline, such as a work order or project identification. For the mill test report to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the mill test report to be complete, it must be signed, stamped, or otherwise authenticated as a genuine and true record of the material by the source of the record or information, in this example it could be the pipe mill, supplier, or testing lab.

Another common record is a pressure test record, which must be traceable, verifiable, and complete. For the pressure test record to be traceable, it would need to identify a specific and unique segment of pipe that was tested (such as mileposts, survey stations, etc.) or have some other link relating the pressure test to the physical location of the test segment, such as a work order, project identification, or alignment sheet. For the pressure test record to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the pressure test record to be complete, it should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, elevation information, and any other information required by § 192.517, as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test.

I. Miscellaneous Issues

iii.—Cost/Benefit Analysis, Information Collection, and Environmental Impact Issues

NPRM Assumptions/Proposals

U.S. Code, title 49, chapter 601, section 60102 specifies that the U.S. Department of Transportation (U.S. DOT), when prescribing any pipeline safety standard, shall consider relevant available gas and hazardous liquid pipeline safety information, environmental information, the appropriateness of the standard, and the reasonableness of the standard. In addition, the U.S. DOT must, based on a risk assessment, evaluate the reasonably identifiable or estimated benefits and costs expected to result from implementation or compliance with the standard. PHMSA prepared a preliminary regulatory impact analysis (PRIA) to fulfill this statutory requirement for the proposed rule and a new regulatory impact analysis (RIA) for this final rule. In addition, PHMSA's Environmental Assessment (EA) is prepared in accordance with NEPA, as amended, and the Council on Environmental Quality (CEQ) regulations for implementing NEPA (40 CFR parts 1500–1508). When an agency anticipates that a proposed action will not have significant environmental effects, the CEQ regulations provide for the preparation of an EA to determine whether to prepare an environmental impact statement or finding of no significant impact.

Summary of Public Comment

Cost Impacts

Several commenters provided input on the cost analysis conducted in the PRIA, providing comments on the structure, assumptions, and unit costs in the PRIA as well as on the lack of accounting for impacts such as the abandonment of pipelines and the cost increase to electricity ratepayers.

Some public interest groups provided input on the cost analysis in the PRIA. EDF stated that the PRIA reasonably addressed uncertainty and lack of information surrounding certain key data assumptions. EDF further stated that the PRIA aligned with Office of Management and Budget guidance on the development of regulatory analysis for rulemakings. They stated that PHMSA used conservative values when making best professional judgments. PST asserted that the costs included in the PRIA for reconfirmation of MAOP, data gathering, record maintenance, and data integration for lines subject to the IM provisions result from the current IM regulations and practices and should not be attributed to this rulemaking. They further stated that the PRIA should be amended to remove these costs related to lines within HCAs.

Several trade associations and industry pipeline entities provided input on the assumptions, methodology, and unit costs used in the PRIA, stating that PHMSA underestimated the cost of complying with the proposed regulations. AGA stated that the organization of the PRIA by ''topic areas'' made it difficult to evaluate the cost estimates of the various provisions of the rule and requested that PHMSA provide a RIA with the final rule that addresses each regulatory section as organized in the preamble. Many commenters, including INGAA, AGA, AGL Resources, and Piedmont, stated that the PRIA underestimated the cost impacts of increased material properties verification, recordkeeping, and MAOP reconfirmation requirements. AGL Resources asserted that complying with the proposed record requirements would involve increased labor and investment costs that should be quantified in the final RIA. AGA stated that it was unclear whether or how the PRIA incorporated material properties verification costs related to material documentation, plan creation, revisions, and testing. NYSEG asserted that the PRIA underestimated the cost impact of the proposed rule on smaller local distribution companies with combined transmission and distribution systems and estimated that they would have to perform IM elements on 8 times the mileage currently in their IM program. Lastly, INGAA provided a higher cost for MAOP confirmation than was estimated in the PRIA due in large part to their assumption that industry would continue to rely on pressure testing, as they asserted that the proposed methods for ILI and ECA are not feasible.

INGAA, AGA, and API submitted detailed cost analyses to the rulemaking docket, while many other commenters (approximately 40) provided estimated unit costs for various provisions of the proposed rule that were generally higher than the unit costs used in the PRIA. For example, Southwest Gas stated that the costs included in the PRIA for options such as ILI and pressure testing were not representative of the costs to their system. With regard to the cost of integrity assessments, BG&E stated that it would cost them over $1 million per year to perform integrity assessments on the additional 100 miles of MCA transmission pipelines, a total which equates to a higher cost per mile estimate than was used in the PRIA. Additionally, New Mexico Gas Co. stated that the proposed rule would cost their company $5.6 million per year to perform integrity assessments on 528 miles of MCA transmission pipe. Vectren estimated the impact to its transmission system would cost $22 million annually. Lastly, PG&E stated that their forecasted costs to implement the proposed rule are significantly higher than the estimates in the PRIA. PG&E provided a comparison of the PRIA costs with their expected expenditures to comply with many provisions in the proposed rule. They projected the cost of compliance would require an upfront investment of $578 million in addition to $222 million per year (as well as a reoccurring cost of $30 million every 7 years) and stated that, comparatively, the PRIA estimates a present value annualized cost of $47 million per year.

Some stakeholders provided input on the estimated number of miles that PHMSA used to determine the regulatory impact of the provisions in the proposed rule. For example, INGAA stated that it assumed the mileage estimated by PHMSA for estimation of MAOP confirmation, material properties verification, and integrity assessments outside HCAs to be accurate with the addition of reportable in-service incidents since last pressure test data. INGAA also asserted that the mileage estimated for MCA transmission pipes should be done on the per-foot basis instead of on the per-mile basis because these pipes are likely to be an aggregation of short pipeline segments that are 1 mile or shorter in length. The North Dakota Petroleum Council asserted that proposed changes in the definition of onshore gathering lines would dramatically increase the number of miles of regulated gathering wells beyond the mileage estimates in the PRIA.

Some commenters asserted that the financial impact of the proposed rule would be immense and that, because operators would not be able to bear these costs alone, they would likely pass the costs on to the ratepayers. For example, APGA stated that all of their member utilities purchase gas and pay transportation charges to transmission pipelines to deliver gas from the producer to the utility. They asserted that ratepayers would pay for the costs that would be incurred by their transmission suppliers to comply with this rule. Similarly, Indiana Utility Regulatory Commission requested that PHMSA consider the costs to ratepayers in its cost analysis. Other commenters stated that this rule could force operators to take significant portions of their pipelines out of service while they are brought into compliance and that the PRIA failed to recognize that FERC requires interstate natural gas pipelines operators to provide demand charge credits to customers when service is disrupted.

Some commenters stated that the proposed rule may cause pipeline abandonment and that these impacts should be considered in the final RIA. Boardwalk Pipeline stated that if a pipe is no longer economic to operate, but FERC does not grant abandonment authority, a pipeline company would be forced to either operate a pipeline that may not meet PHMSA standards or undertake expensive replacement projects. Boardwalk Pipeline further stated that while operators may seek to recover the costs of replacement projects through rate increases, in a competitive pipeline market where operators are forced to discount their pipeline rates in order to retain customers, these costs might be too great to recover. Similarly, the Independent Petroleum Association of America stated that the PRIA failed to account for the costs that could be incurred by operators if pipeline infrastructure is abandoned because the cost that would be required to comply with the rule would necessitate this abandonment. The Public Service Commission of West Virginia suggested that, should operators abandon wells and pipelines due to the requirements of this proposed rule, it could cause an environmental and economic liability for State regulators if operators abandon wells and pipelines without proper clean up.

Several commenters expressed concern that PHMSA's cost-benefit analysis does not meet the requirements established by the 2011 Pipeline Safety Act and the Administrative Procedures Act (APA). Trade associations stated that the PRIA does not fulfill PHMSA's statutory obligations because it omits relevant costs, relies on incorrect assumptions, and contains multiple inconsistencies. INGAA asserted that the PRIA does not comply with the APA because the finding in the PRIA that the proposed benefits outweigh the costs is contingent on an underestimation of the costs of the proposed rule. INGAA also noted that flawed cost-benefit analysis can be grounds for courts to reject agency rulemakings. INGAA asserted that the proposed rulemaking does not comply with the Paperwork Reduction Act (PRA), because PHMSA's estimate of the information collection burden did not include the costs of these additional recordkeeping requirements for transmission pipeline operators.

Benefit Estimates

PHMSA also received comments on the benefits associated with the proposed rule. Physicians for Social Responsibility expressed their support of the proposed rule and the analysis of reduced accidents and increased worker safety in the PRIA. Additionally, Physicians for Social Responsibility stated that many harmful air pollutants, such as nitrous oxide, sulfur dioxide, particulate matter, formaldehyde, and lead, are all associated with gas pipelines and compressor stations. They further stated that this rule would help reduce or mitigate this pollution and that these public health benefits should be accounted for in the benefits calculations.

Other commenters, including AGA and INGAA, stated that PHMSA overestimated the damage caused by incidents in the quantification of benefits in the PRIA. AGA stated that PHMSA allowed one major incident to skew the data in their benefits analysis and proposed that PHMSA adopt a new approach to quantify the benefits of reduced accidents. INGAA stated that using data from the past 13 years skewed the results and that the most recent 5 years of incident history would more reasonably reflect positive developments in pipeline safety, given that significant developments in pipeline safety have occurred within this time period.

Several commenters provided input on the proposed use of the social cost of carbon and the social cost of methane in the PRIA. EDF and National Resource Defense Council supported the use of the social costs of carbon and methane methodology in the PRIA. However, these commenters stated that the estimates for social costs of carbon and methane were likely too conservative and that the values should be higher than those used in the PRIA. These commenters stated that PHMSA should encourage the Interagency Working Group on Social Cost of Carbon to update regularly the social cost of carbon and social cost of methane as new economic and scientific information emerges. API stated that the proposed use of the social cost of methane to calculate the benefits of emissions reductions was flawed due to the discount rates used by PHMSA. They asserted that PHMSA used low discount rates that led to a liberal damage estimate. In addition, API and Industrial Energy Consumers of America asserted that the social cost of carbon values used by PHMSA inappropriately impose global carbon costs on domestic manufacturers, which damages the industry's ability to compete internationally. AGA stated that the process used to develop the social cost of methane values in the PRIA did not undergo sufficient expert and peer review. INGAA stated that PHMSA overestimated the amount of greenhouse gas emissions that the rule would reduce.

Environmental Impacts

Several commenters noted that the 2011 Pipeline Safety Act mandates that PHMSA consider the environmental impacts of proposed safety standards. Citizen groups stated that the proposed regulation fulfills this statutory obligation and is a step forward in reducing methane emissions from natural gas pipelines. Multiple citizen groups emphasized the consequences of climate change, the high global warming potential of methane, and the responsibility of natural gas systems for a significant portion of U.S. methane emissions. Citizen groups underlined the importance of regulating methane leaks and considering methane's climate implications in natural gas regulations. The Lebanon Pipeline Awareness Group addressed local environmental impacts, requesting that pipelines not be permitted to contaminate agricultural soils.

Trade associations asserted that PHMSA did not fulfill its statutory obligation to consider the full environmental impacts of the proposed safety standards, suggesting that PHMSA failed to consider several topics in the NPRM that would have direct environmental impacts. These commenters claimed that certain topics and their impacts, including IM clarifications, MAOP reconfirmation, and hydrostatic pressure testing, were mischaracterized in the EA, and that PHMSA further underestimated the number of excavations that would need to be made per the proposal as well as the impacts of procuring and disposing of water for hydrostatic tests.

Trade associations further expressed concerns that, while PHMSA had addressed the emissions avoided under the proposed rule, PHMSA had not addressed the extent to which the proposed rule would increase emissions. AGA and INGAA noted that operators need to purge lines of natural gas before conducting hydrostatic tests or removing pipelines from service for replacement or repair. These commenters stated that the proposed regulation would increase methane emissions by increasing the number of hydrostatic tests, pipeline replacements, and pipeline repairs required and asserted that the EA did not take the increased emissions from these blowdowns into account. INGAA asserted that not considering these methane emissions constituted a violation of the 2011 Pipeline Safety Act and failure to ''engage in reasoned decision making.'' INGAA also suggested that the methane emissions resulting from this rulemaking would run counter to President Obama's goals of reducing methane emissions.

EDF and PST commissioned a study from M.J. Bradley & Associates (MJB&A) that calculated the extent to which the proposed rule would result in blowdown emissions. MJB&A found that potential methane emissions resultant from the proposed rule would increase annual methane emissions from natural gas transmission systems by less than 0.1 percent and increase annual methane emissions from transmission system routine maintenance by less than one percent. MJB&A also noted five mitigation methods that if implemented, could decrease blowdown emissions by 50 to 90 percent.[75] MBJ&A calculated that the societal benefits of methane reduction outweighed the mitigation costs for all mitigation options considered. Based on this study, EDF asserted that while the marginal increase in emissions from the proposed rule would be small, the total emissions from blowdowns would nonetheless be significant. They stated that PHMSA should require operators to select and implement one of the mitigation options and report to PHMSA information about their blowdown events, such as the mitigation option selected and the amount of product lost due to blowdowns required by the proposed rule. EDF also stated that if operators do not mitigate blowdown emissions, they should be required to provide an engineering or economic analysis demonstrating why mitigation is deemed infeasible or unsafe.

AGA stated that the EA did not address other environmental impacts resultant from hydrostatic pressure testing. AGA noted two anticipated water-related impacts: (1) Hydrostatic pressure testing's water demand could aggravate water scarcity in already water-scarce environments, and (2), the water used in hydrostatic tests could introduce contaminants if disposed on-site (or be very expensive to transport to off-site disposal). AGA explained that wastewater from hydrostatic tests could include hydrocarbon liquids and solids, chlorine, and metals.

AGA also asserted that the EA did not adequately consider the land disturbances that could result from the proposed hydrostatic testing requirements, nor did it consider that performing inline inspections and modifying pipelines to accommodate inline inspection tools would generate waste and disturb natural lands. AGA explained that operators must clean pipelines prior to conducting inline inspections or modifying pipelines for inline inspection tools and that this cleaning could produce large volumes of pipeline liquids, mill scale, oil, and other debris. AGA expressed concerns that the proposed EA did not discuss these environmental impacts associated with requiring MAOP confirmation, given that PHMSA anticipates that most affected pipelines would verify MAOP using ILI and pressure testing.

AGA also provided input on the local environmental impacts of the proposed increased testing and inspection. AGA expressed concerns that the EA had (1), underestimated the quantity of excavations that would be required under the proposed rule, and (2), inadequately assessed the environmental impacts of those excavations. AGA asserted that the EA had insufficiently considered the extent to which more excavations would generate water and soil waste. AGA also suggested that the proposed rule may

[75] The methods are (1) gas flaring; (2) pressure reduction prior to blowdown with inline compressors; (3) pressure reduction prior to blowdown with mobile compressors; (4) transfer of gas to a low-pressure system; and (5) reducing the length of pipe requiring blowdown by using stopples.

induce operators to modify or replace pipelines and that these modifications and replacements may affect land beyond existing rights of way. AGA asserted that this additional land area should be considered in the EA.

Trade associations raised other technical issues regarding the EA. AGA expressed concerns that PHMSA provided insufficient information about methods used to calculate values in the EA and that this insufficient documentation interfered with stakeholders' ability to provide comments on the values that PHMSA chose. INGAA asserted that the proposed rule fell short of several legal obligations under NEPA, stating that the EA does not provide the required ''hard look'' at environmental impacts, that the EA does not adequately discuss the indirect and cumulative effects of the proposed rule, and that the purpose and need statement in the EA do not fulfill NEPA instructions. INGAA also expressed concern that PHMSA did not consider sufficient regulatory alternatives, stating that the EA considered solely the proposed rule, one regulatory alternative, and the no action alternative. INGAA stated that given the many provisions of the proposed rule, this approach was too limited.

Other Impacts

Some trade associations and pipeline industry entities provided input that the PRIA failed to account for the indirect effects of operators shifting resources to comply with the proposed rule. For example, AGA stated that the PRIA did not consider the potential indirect impacts the rule might impose on distribution lines. They asserted that the magnitude and prescriptiveness of the proposed rule would require distribution companies with intrastate transmission and distribution assets to reassign their limited resources to transmission lines.

Some commenters stated that PHMSA did not consider that the proposed rule would divert resources away from voluntary safety programs their companies are initiating, stating that these voluntary safety measures would be scaled back because of the proposed rule. For example, AGA stated that accelerated pipe replacement programs that replace aging cast iron, unprotected steel pipe, and vintage plastic pipe, would lose resources as operators shift staff and capital to comply with the proposed rule. They further asserted that failing to replace these pipes would delay reductions in methane emissions from old, leaky pipes.

PHMSA Response

Cost Impacts

PHMSA has reviewed the comments related to the RIA for the proposed rule and has revised the final analysis consistent with the final rule and in consideration of the comments. PHMSA addressed the comments received on the RIA in two key ways. First, PHMSA revised many of the requirements in the final rule, including (a) revising or clarifying that the final provisions do not apply to gas distribution or gas gathering pipelines; (b) revising MAOP reconfirmation requirements for grandfathered pipelines to include only those lines with MAOP greater than or equal to 30 percent SMYS; (c) streamlining the process for operators to use an alternative technology for MAOP reconfirmation; (d) removing the term ''occupied sites'' in the MCA definition; and (e) revising the records provisions to remove certain proposed provisions and clarifying that the new requirements are not retroactive. These changes, as well as others made in the final rule, result in less costly and more cost-effective requirements. Second, in response to comments received, PHMSA made several revisions to the analysis conducted in the RIA for the proposed rule, discussed below. Also, in response to comments, PHMSA revised the final RIA to align more closely to the preamble organization.

PHMSA acknowledges the baseline issues associated with establishing MAOP, data collection, and other provisions noted in the comments. In the final RIA, PHMSA is including estimated incremental costs to reconfirm MAOP for lines within HCAs based on a current compliance baseline. Attributing compliance to existing pipeline safety regulations would reduce both the costs and benefits of the final rule. Regarding the comments that the RIA for the proposed rule underestimated the cost impacts of material properties verification, recordkeeping, and MAOP confirmation, as discussed above, the changes to the scope and applicability of the MAOP reconfirmation, data, and recordkeeping provisions result in common-sense, cost-effective requirements. For example, PHSMA designed the final requirements for material properties verification to allow operators the option of a sampling program that opportunistically takes advantage of repairs and replacement projects to verify material properties simultaneously. The final provisions allow, over time, operators to collect enough information to gain significant confidence in the material properties of pipe subject to this requirement.

Further, as discussed under the section regarding the material properties verification process, the final rule removes the applicability criteria of the material properties verification requirements and makes a procedure for obtaining pipeline physical properties and attributes that are not documented in traceable, verifiable, and complete records or for otherwise verifying pipeline attributes when required by MAOP reconfirmation requirements, IM requirements, repair requirements, or other code sections. Therefore, due to the changes made from the proposed rule, the material properties verification requirements mandated by section 23 of the 2011 Pipeline Safety Act represent a cost savings in comparison to existing regulations, although PHMSA has not quantified those savings.

With regard to the operator-provided cost information or estimates of the proposed rule, the commenters' estimates were not transparent enough for PHMSA to discern the assumptions and inputs underlying the estimates. As a result, PHMSA could not reliably confirm whether the cost information accurately reflected the quantity and character of the actions required by the proposed rule. To improve the transparency of the analysis and address commenters' concerns about PHMSA's reliance on best professional judgment in the RIA for the proposed rule, PHMSA contacted five vendors of pipeline inspection and testing services to obtain updated cost estimates for several unit costs that were based on best professional judgement in the RIA for the proposed rule. These vendors provided representative incremental costs associated with the final rule requirements. In the final RIA, PHMSA used prices provided by vendors to estimate unit costs for all MAOP reconfirmation and integrity assessment methods, as well as for upgrades to launchers and receivers.

Regarding MAOP reconfirmation specifically, in the RIA for the proposed rule PHMSA assumed operators would conduct MAOP reconfirmation using either pressure testing or ILI. In the final RIA, based on feedback received during a GPAC meeting,[76] PHMSA assumed that operators would reconfirm MAOP using a mix of all six available compliance methods.

Additionally, in the final RIA, PHMSA analyzed the requirements for MAOP reconfirmation and integrity

[76] GPAC Meeting, March 26–28, 2018. For a transcript of the meeting, see *https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=970.*

assessments outside HCAs for each operator individually based on the information they submitted in their Annual Reports. Based on the information in operator Annual Reports and the final rule requirements for MAOP reconfirmation, some operators will incur less of an impact than indicated by their public comments.

Regarding the comment that the proposed changes to the definition of onshore gathering lines would dramatically increase the number of miles of regulated gathering wells beyond the mileage estimates in the RIA for the proposed rule, this final rule does not change the definition of gathering pipelines.

With respect to pipelines located within MCAs, PHMSA confirmed the analysis of the length of gas transmission pipelines located within MCAs in the RIA for the proposed rule by integrating additional spatial data from the U.S. Census Bureau, U.S. Geological Survey, Environmental Systems Research Institute, and Tele-Atlas North America, Inc. For additional details on the MCA GIS analysis, see section 5.7 of the RIA for the final rule. This allowed PHMSA to confirm the number of impacted miles. Additionally, due to existing state MAOP reconfirmation requirements, PHMSA updated the RIA to reflect that impacts in California are not attributable to the rule. Lastly, PHMSA presented all impacted mileage on a dollar-per-foot basis instead of dollars per mile, based on comments received that these pipeline segments are likely to be an aggregation of short pipeline segments that are a mile or shorter in length.

Regarding the comment that PHMSA underestimated the cost impact of the proposed rule on smaller local distribution companies with combined gas transmission and gas distribution systems, PHMSA conducted an analysis of the rule's impact on small entities by comparing entity-level cost estimates to annual entity revenues and identifying entities for which annualized costs may exceed 1 percent and 3 percent of revenue. As documented in the final Regulatory Flexibility Act (FRFA) analysis, PHMSA relied on conservative assumptions in performing this sales test, which may overstate, rather than understate, compliance costs for small entities. PHMSA found that the final rule will not have a significant economic impact on small entities.

PHMSA does not agree that the final rule requirements constitute a significant energy action. PHMSA agrees with the comment that the costs would be passed on to ratepayers; however, PHMSA disagrees that these costs would be immense. E.O. 13211 requires agencies to prepare a Statement of Energy Effects when undertaking certain agency actions if, among other criteria, the regulation is expected to see an increase in the cost of energy production or distribution in excess of one percent. The annualized cost of these requirements represents less than 0.1 percent of pipeline transportation of natural gas (North American Industry Classification System code 486210) industry revenues ($25 billion), adjusting the 2012 Economic Census value into 2017 dollars using the Gross Domestic Product Implicit Price Deflator Index. Therefore, in the aggregate it is extremely unlikely that these requirements would cause a significant increase in costs that utilities would pass on to the ratepayer.

Available information supports that, in the baseline, operators are replacing or abandoning certain pipelines regardless of the implementation of this rule as well as taking other actions such as making lines piggable.[77] As discussed above, in the final RIA, PHMSA assumed some use of pipe replacement and abandonment as a means of operators reconfirming MAOP. However, the costs of replacing infrastructure operating beyond the design useful life are not attributable to safety regulations and investment in plant, including a return on investment, are already recovered through rates.

The RIA for the final rule meets all PHMSA's requirements under applicable acts and executive orders. The analysis involves estimating a baseline scenario and changes under the regulation. PHMSA has used its judgement, available data, information, and analytical methods to develop an analysis of the baseline and incremental costs and benefits under the rule. As discussed above, some costs and benefits may be attributable to existing requirements and some may occur in the absence of the rule.

Benefits Estimates

PHMSA agrees that recent data is more reflective of recent improvements in pipeline safety and performance relative to current standards. For the final RIA, PHMSA used more recent data on pipeline incidents from 2010 to 2017 versus the 2003 to 2015 data used in the RIA for the proposed rule. PHMSA used the data from 2010 on because PHMSA updated its incident reporting methodology in 2010, and this period therefore provides the largest available sample of consistently reported incident data. Regarding the benefits analysis for the preliminary RIA developed for the NPRM potentially being skewed by one major incident (the PG&E incident at San Bruno), there is no evidence that more serious incidents are not possible in the future in the absence of the regulation, and therefore, PHMSA does not exclude this incident when qualitatively assessing benefits. At the same time, and although PHMSA developed this rule to prevent future, similar incidents, PHMSA cannot know with certainty whether a similar incident would occur again absent this rulemaking. According to the historical record, serious incidents, like the one occurring at San Bruno, occur approximately once per decade. For example, on August 19, 2000, a 30-inch-diameter natural gas transmission pipeline operated by the El Paso Natural Gas Company ruptured adjacent to the Pecos River near Carlsbad, NM. The released gas ignited and burned for 55 minutes. Twelve persons camping near the incident location were killed, and their three vehicles were destroyed.[78] Similarly, on March 23, 1994, a 36-inch-diameter natural gas transmission pipeline owned and operated by Texas Eastern Transmission Corporation ruptured in Ellison Township, NJ. The incident caused at least $25 million in damages, dozens of injuries, and the evacuation of hundreds.[79] More detailed data on current pipeline integrity in relation to populations and the environment would enable more detailed predictions of the benefits of regulations.

Due to the speculative nature of predicting the occurrence, avoidance, and character of specific future pipeline incidents, in the final RIA, PHMSA elected not to quantify the rule's benefits. PHMSA uses this approach rather than make highly uncertain predictions about both a specific number of future incidents avoided due to the final rule, and the character of avoided incidents with respect to effects on benefit-analysis endpoints (*e.g.,* fatalities, injuries, evacuation). The

[77] PG&E. 2011. ''Pacific Gas And Electric Company's Natural Gas Transmission Pipeline Replacement Or Testing Implementation Plan.'' California Public Utilities Commission; Consolidated Edison Company Of New York. 2016. ''Consolidated Edison Company Of New York, Inc. 2017–2019 Gas Operations Capital Programs/Projects.'' New York State Department of Public Service. *http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-G-0061&submit=Search.*

[78] Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico, August 19, 2000, Pipeline Accident Report, NTSB/PAR–03/01, Washington, DC.

[79] Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Pipeline Accident Report, NTSB/PAR–95–01, Washington, DC.

quantified benefits for each provision therefore represent the quantity of a given benefit category required to achieve a dollar value equal to the provision's compliance cost.

PHMSA does not have data on harmful air pollutants such as nitrous oxide, sulfur dioxide, particulate matter, formaldehyde, and lead associated with gas pipelines and compressor stations, or the reductions in these pollutants under the rule. Therefore, the analysis did not address the environmental costs associated with these pollutants. PHMSA did not include estimates of benefits based on the social cost of methane for the final rule.

Environmental Impacts

Regarding the comments stating that the preliminary EA did not adequately consider the air emissions that would result from hydrostatic pressure testing, inline inspections, excavations, and MAOP reconfirmation, PHMSA revised the EA to address this issue. Commenters asserted that by increasing the number of hydrostatic tests, pipeline replacements, and pipeline repairs required, the proposed provisions would increase methane ''blowdown'' emissions that result from the required purging of natural gas pipelines before conducting these actions. PHMSA revised the EA to include a discussion of the study conducted by M.J. Bradley & Associates (MJB&A) [80] that calculated the extent to which the proposed rule would result in blowdown emissions.

MJB&A found that unmitigated blowdown from the miles of transmission pipeline that would be required to conduct a MAOP determination would release an average of 1,353 metric tons per year of methane to the atmosphere for the 15-year compliance period [81] proposed by PHMSA. By comparison, historical unintentional releases from natural gas transmission pipelines outside of HCAs with piggable lines greater than 30 percent SMYS (a universe of facilities that could be subject to MAOP reconfirmation in MCAs) averaged 13,500 metric tons per year from 2010 to 2017. These releases were caused by 163 incidents that released an average of 663.4 metric tons per incident.[82]

Therefore, if the final rule requirements avoided two average incidents per year, the rule would not result in any net methane releases. MJB&A further stated that the potential methane emissions resultant from the NPRM would increase annual methane emissions from natural gas transmission systems by less than 0.1 percent and increase annual methane emissions from transmission system routine maintenance/upsets by less than one percent. Given these factors, PHMSA does not believe that the final rule will result in a significant, if any, increase in methane releases.

In response to comments, PHMSA revised the EA to also include a discussion of water-related impacts resulting from hydrostatic pressure testing as well as waste generation land disturbances from hydrostatic pressure testing and inline inspections. Operators must conduct all waste and wastewater disposal activities in accordance with federal, state, and local regulations and permit requirements, and the final rule requires processes and procedures in which pipeline operators are already familiar with respect to pipeline IM. Regarding the comments on the environmental impacts of pipe replacement, as discussed above, the impacts of replacing infrastructure that is operating beyond the design useful life are not attributable to the final rule requirements. While the final RIA assumes that operators will comply with MAOP reconfirmation using pipe replacement for approximately 300 miles of pipe, PHMSA did not consider these replacements to be incremental costs. Similarly, the environmental impacts are not attributable to the final rule requirements.

Other Impacts

PHMSA disagrees with the analysis of operators shifting resources away from safety programs to comply with the proposed rule. PHMSA has revised and clarified the pipeline safety and integrity applicability of the final rule such that many operators will incur lower costs than previously anticipated. The final rule also provides long compliance schedules to enable planning for efficient compliance actions.

IV. GPAC Recommendations

This section briefly summarizes the NPRM proposals, the GPAC's major comments on the proposals discussed, and the recommendations of the committee regarding how those provisions should be finalized. More detail, the presentations, and the transcripts from all of the meetings are available in the docket for this rulemaking.[83] The provisions, which are presented in the order they were discussed at the GPAC meetings, the changes the committee agreed upon, and the corresponding vote counts are as follows:

6-Month Grace Period for 7-Calendar-Year Reassessment Intervals (§ 192.939(b))

In the NPRM, PHMSA proposed to allow operators to request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to the Secretary with sufficient justification of the need for the extension in accordance with the technical correction at section 5 of the 2011 Pipeline Safety Act. The committee had no objections or substantial comments on this provision and voted 12–0 that it was, as published, technically feasible, reasonable, cost-effective, and practicable.

Safety Features on ILI Launchers and Receivers (§ 192.750)

In the NPRM, PHMSA proposed to require operators equip ILI tool launchers and receivers with a device capable of safely relieving pressure in the barrel before the insertion or removal of ILI tools, scrapers, or spheres. Further, PHMSA proposed requiring operators to use a suitable device to indicate that pressure has been relieved in the barrel or otherwise provide a means to prevent the opening of the barrel if pressure has not been relieved. The committee voted 12–0 that this provision was, as published, technically feasible, reasonable, cost-effective, and practicable, as long as PHMSA clarified that the rule language does not require ''relief valves'' or use ''relief valve'' as a term. Some committee members were concerned that using language related to ''relief valves'' would bring in other code requirements, which was not PHMSA's intent.

Seismicity (§§ 192.917, 192.935(b)(2))

In the NPRM, PHMSA proposed to include seismicity in the list of factors operators must evaluate for the threat of outside force damage when considering preventative and mitigative measures, as well as include the seismicity of an area as a pipeline attribute in an operator's data gathering and integration when performing risk analyses. The committee had no substantial comments or recommendations on this topic, and

[80] The study was commissioned by EDF and PST and is available at *http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf.*

[81] See § 192.624(b).

[82] ''Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data.'' Phmsa.Dot.Gov. 2017. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.*

[83] *https://www.regulations.gov/docket?D=PHMSA-2011-0023.*

they voted 12–0 that this provision was, as published, technically feasible, reasonable, cost-effective, and practicable.

Records (§§ 192.5(d), 192.13(e), 192.67, 192.127, 192.205, 192.227(c), 192.285(e), 192.619(f), 192.624(f), Appendix A)

In the NPRM, PHMSA proposed to clarify that the records required by part 192 must be documented in a reliable, traceable, verifiable, and complete manner. PHMSA summarized the recordkeeping requirements of part 192 in a new Appendix A, and required that operators must re-establish pipeline documentation whenever records were not available and make and retain records demonstrating compliance with part 192. Issues related to records were discussed through the final 4 GPAC meetings over the course of 2017 and 2018. The committee found the assorted provisions related to records as being technically feasible, reasonable, cost-effective, and practicable, if certain changes were made. Specifically, the committee recommended the word ''reliable'' be deleted from the records standard so that it reads ''traceable, verifiable, and complete'' records wherever the standard is used. Members noted that the NTSB never used the term ''reliable,'' and a PHMSA advisory bulletin reflects the language without referring to ''reliable'' records. In the class location requirements at § 192.5, the committee recommended PHMSA clarify that documentation be required to substantiate the current class location and not previous historical ones. The committee also recommended that PHMSA modify the requirements for the qualification of welders and persons joining plastic pipe to include an effective date and change the records retention provision to a period of 5 years.

During the June 2017 GPAC meeting, the committee recommended PHMSA amend provisions related to the general duty clause for records and edit the corresponding reference to retention periods in Appendix A. After further discussion, during the meeting on March 2, 2018, the committee recommended PHMSA withdraw the proposed addition of § 192.13. Similarly, in the June 2017 meeting, the committee recommended PHMSA modify the proposed Appendix A to clarify that it does not apply to distribution or gathering pipelines. After considering the issue at the meeting on March 2, 2018, the committee recommended PHMSA withdraw proposed Appendix A from the rulemaking.

Other changes the committee suggested regarding the proposed recordkeeping requirements included revising the record provisions for materials, pipe design, and components to clarify the effective date of those provisions and recommended PHMSA clarify that the recordkeeping provisions for components only applies to components greater than 2 inches in nominal diameter. The recordkeeping provisions proposed under the MAOP determination and MAOP reconfirmation sections were discussed by the GPAC separately and are expanded upon under the discussions for those specific topics below.

Following those discussions over the course of multiple meetings, the committee voted unanimously that the provisions related to recordkeeping requirements in part 192 were technically feasible, reasonable, cost-effective, and practicable, if PHMSA made the changes outlined above.

IM Clarifications (§§ 192.917(e)(2), (e)(3) & (e)(4))

In the NPRM, PHMSA proposed several changes to provisions related to how operators use data in their IM programs and manage certain types of defects. PHMSA proposed changes regarding an operator's analysis of cyclic fatigue and clarifying that certain pipe, such as low-frequency electric resistance welded pipe, must have been pressure tested for an operator to assume that any seam flaws are stable. PHMSA also proposed that any failures or changes to operation that could affect seam stability must be evaluated using a fracture mechanics analysis.

Regarding cyclic fatigue, some GPAC members expressed concern that PHMSA proposed to require an annual analysis of cyclic fatigue even if the underpinning conditions affecting cyclic fatigue had not changed. Certain GPAC members wanted to ensure that it would be a change in conditions that would trigger an evaluation and that operators would not necessarily need to do an evaluation within a certain period otherwise. During the meeting, PHMSA suggested it would consider changing cyclic fatigue analysis from annually to periodically based on any changes to cyclic fatigue data and other changes to loading conditions since the previous analysis was completed, not to exceed 7 calendar years. Further, PHMSA would consider whether there was conflict with this section and the MAOP reconfirmation requirements, which was a concern brought up during the public comment period of the meeting. Following the discussion, the committee voted 11–0, that the provisions related to cyclic fatigue were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the paragraph based on the GPAC member discussion and PHMSA's proposed language at the meeting.

For the provisions related to the stability of manufacturing- and construction-related defects, PHMSA proposed during the GPAC meeting to provide that an operator could consider manufacturing- and construction-related defects as stable only if the covered segment has been subjected to a subpart J pressure test of at least 1.25 times MAOP and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J pressure test. Pipeline segments that have experienced a reportable incident since its most recent subpart J pressure test due to an original manufacturing-related defect, a construction-related defect, an installation-related defect, or a fabrication-related defect would be required to be prioritized as a high-risk segment for the purposes of a baseline assessment or a reassessment. PHMSA proposed to explicitly lay out these requirements in the regulations rather than cross-reference these requirements to the MAOP reconfirmation provisions. Additionally, PHMSA indicated it would create a stand-alone section to deal with pipeline cracking issues within the IM regulations and would delete a specific reference to ''pipe body cracking'' in the provisions related to electric resistance welded pipe.

Following the discussion, the committee voted 12–0 that the provisions related to IM clarifications regarding manufacturing and construction defects were technically feasible, reasonable, cost-effective, and practicable if PHMSA made the changes it proposed during the meeting, created a new, stand-alone section for addressing pipeline cracking within the IM regulations, deleted the phrase related to ''pipe body cracking,'' and considered allowing other test procedures for determining whether manufacturing- and construction-related defects were stable.

MAOP Exceedances (§§ 191.23, 191.25)

In the NPRM, PHMSA proposed requiring operators to report each exceedance of the MAOP that exceeds the build-up allowed for the operation of pressure-limiting or control devices per the congressional mandate provided in the 2011 Pipeline Safety Act, which requires operators to report such exceedances on or before the 5th day following the date on which the exceedance occurs.

During the public comment period of the June 7, 2017, meeting, a commenter expressed concern that being required to report an exceedance within 5 days might be problematic where an ongoing investigation might preclude an operator from being able to complete a full safety-related condition report. The GPAC considered this viewpoint but noted that the 5-day reporting requirement was prescribed by statute, and PHMSA does not have discretion when implementing that deadline. The GPAC, echoing another comment from the public, discussed whether the provision would be applicable to gathering lines. PHMSA, in response, noted that the requirement would be limited to gas transmission lines only. Following the discussion, the GPAC voted 11–0 that the provision was technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that this provision does not apply to gathering lines.

Verification of Pipeline Material Properties and Attributes (§ 192.607)

In the NPRM, PHMSA proposed a process for operators to re-establish material properties on pipelines where those attributes may be unknown. The process was an opportunistic sampling approach that did not require any mandatory excavations and allowed operators to verify material properties of pipelines as opportunities presented themselves during normal operations and maintenance, such as excavations for the repair of anomalies.

The GPAC had a robust discussion on the proposed material properties verification requirements and wanted to clarify that two separate activities—MAOP reconfirmation and the application of IM principles—drive the need for material properties verification and should be addressed separately. Overall, the GPAC was supportive of PHMSA's opportunistic approach for verifying material properties. During the public comment period, members representing the pipeline industry suggested PHMSA allow a statistical sampling plan developed by operators instead of prescribing a specific number of samples needed. PHMSA clarified that it expected a 1 pipe-per-mile sampling standard in most cases.

At the December 2017 GPAC meeting, some GPAC members expressed concern with the specific attributes PHMSA was proposing operators collect and verify. There was also some discussion regarding how the notification procedure PHMSA proposed might be cumbersome if operators would be required to wait on a response or action from PHMSA every time an operator wanted to submit an alternative plan. The GPAC suggested adding language where, if PHMSA was to object to an operator notification, they would have to object within 90 days. If PHMSA did not object within 90 days, the operator would be free to go forward with the intended action.

Following the discussion, the GPAC voted 12–0 that the provisions related to material properties verification were technically feasible, reasonable, cost-effective, and practicable if the following changes were made:

- Clarify that material properties verification applies to onshore steel transmission lines only, and not distribution or gathering lines.
- Remove the applicability criteria of the section and make the material properties verification provisions a procedure that operators can use for obtaining missing or inadequate records or verifying pipeline attributes if required by the MAOP reconfirmation provisions or other code sections. The committee agreed to address the applicability of the material properties verification requirements under each of the MAOP reconfirmation methods and other sections as appropriate.
- Delete the requirements for creating a material properties verification program plan.
- Drop the list of mandatory attributes operators would be required to verify but require that operators keep any records developed through this material properties verification method.
- Retain the opportunistic approach of obtaining unknown or undocumented material properties when excavations are performed for repairs or other reasons, using a one-per-mile standard proposed by PHMSA, but allow operators to use their own statistical approach and submit a notification to PHMSA with their method. Establish a minimum standard of a 95% confidence level for operator statistical methods submitted to PHMSA.
- Retain flexibility to allow either destructive or non-destructive tests when verification is needed.
- Incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. PHMSA will notify the operator if additional review time is needed.
- Revise the paragraph to accommodate situations where a single material properties verification test is needed (*e.g.,* additional information is needed for an anomaly evaluation/repair).
- Drop accuracy specifications (retain requirement that test methods must be validated and that calibrated equipment be used).
- Drop mandatory requirements for multiple test locations for large excavations (multiple joints within the same excavation).
- Reduce number of quadrants at which NDE tests must be made from 4 to 2.
- Delete specified program requirements for how to address sampling failures and replace with a requirement for operators to determine how to deal with sample failures through an expanded sample program that is specific to their system and circumstances. Require notification to provide expanded sample program to PHMSA, and require operators establish a minimum standard that sampling programs must be based on a minimum 95% confidence level.
- Clarify the applicability of § 192.607 (d)(3)(i).

Strengthened Assessment Requirements (Appendix F, §§ 192.493, 192.506, 192.921(a))

In the NPRM, PHMSA proposed to clarify the selection and conduct of ILI tools per updated industry standards that would be incorporated by reference, clarify the consideration of uncertainties in ILI reported results, add additional assessment methods to allow greater flexibility to operators, and allow direct assessment as a method only if the pipeline was not piggable. PHMSA also proposed to explicitly allow guided wave ultrasonic testing (GWUT) in the list of integrity assessment methods by codifying in a new Appendix F the current guidelines operators use for submitting GWUT inspection procedures.

For the updated ILI standards, some GPAC members requested PHMSA delete the ''requirements and recommendations'' language in § 192.493 and other places where standards are incorporated by reference to avoid the consequence that non-mandatory recommendations in the standards would become regulatory requirements. Following the discussion, the GPAC voted 10–0 that the provisions related to strengthened assessment requirements pertaining to in-line assessment standards were technically feasible, reasonable, cost-effective, and practicable if PHMSA struck the phrase ''the requirements and recommendations of'' from the appropriate paragraph in § 192.493.

Regarding the usage of assessment methods, certain committee members recommended PHMSA allow the direct assessment method whenever appropriate (*i.e.,* do not restrict the use of direct assessments to unpiggable pipeline segments or when other methods are impractical) and incorporate better language to clarify when it is appropriate for operators to use direct assessments. Similarly, the GPAC suggested PHMSA clarify the regulatory language so that it was clear operators must select the appropriate assessment method based on the applicable threats. The clarification would avoid the implication that operators need to run certain tools against certain threats when there is no evidence or susceptibility of that threat for that particular pipeline segment.

The GPAC also recommended that PHMSA delete the proposed requirement in the baseline assessment method that required a review of ILI results by knowledgeable individuals, since it is duplicative with other existing requirements elsewhere in the regulations. Further, some GPAC members expressed concern that all tools cannot meet the 90 percent tool tolerance that is specified in the referenced industry standard. PHMSA representatives noted that the rule would not require that every tool perform within a 90 percent specification rate, but that actual tool performance should be verified and applied when ILI data is interpreted. As in other sections of the proposed regulations, the committee also requested PHMSA adopt the same objection procedure that the GPAC discussed and approved under the material properties verification provisions for any notification under this section.

Following the discussion, the GPAC voted 10–0 that the provisions related to strengthening the conduct of a baseline integrity assessment were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the requirements to clarify that operators must select assessment methods based on the threats to which the pipeline is susceptible and removed language in the provision that is duplicative with requirements elsewhere in the regulations; clarified that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable; and incorporated the same objection procedure the committee approved for the material properties verification provisions and with a PHMSA review timeframe of 90 days.

In discussing the provisions related to the ‘‘spike’’ hydrostatic pressure test method, the committee had several comments and recommendations. Specifically, some GPAC members recommended that the spike test should be performed at a pressure level of 100 percent SMYS, and not 105 percent, to account for varying elevations and test segment lengths. They also suggested that the 30-minute hold time was too long and requested PHMSA consider minimizing the duration of the spike pressure to avoid growing subcritical cracks. Further, the GPAC recommended PHMSA clarify that spike testing should be performed against the threat of ‘‘time-dependent cracking’’ and remove instances in other sections of the regulations where PHMSA listed the threats for which a spike pressure test is appropriate. Following the discussion, the committee voted 10–0 that the provisions related to the ‘‘spike’’ hydrostatic pressure test method were technically feasible, reasonable, cost-effective, and practicable if PHMSA changed the minimum spike pressure to whichever is lesser: 100 percent SMYS or 1.5 times MAOP, reduced the spike hold time to a minimum of 15 minutes after the spike pressure stabilizes, referred to ‘‘time-dependent cracking’’ in the section, incorporated the same objection procedure the committee approved for the material properties verification provisions and with a PHMSA review timeframe of 90 days, and incorporated the term ‘‘qualified technical subject matter expert’’ (SME) at the SME requirements.

The GPAC did not have major concerns with incorporating the GWUT procedures into the regulations and voted 13–0 that the provisions related to the GWUT process were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the objection procedure as recommended by GPAC members during the discussion on the proposed material properties verification requirements and considering certain minor technical recommendations made by the GPAC members.

Moderate Consequence Area Definition (§ 192.3)

In the NPRM, PHMSA proposed a new definition for ‘‘Moderate Consequence Areas’’ (MCA) which would be areas operators would have to assess per the proposed requirements for performing integrity assessments outside of HCAs. PHMSA proposed to define an MCA as an area in a ‘‘potential impact circle’’ [84] with 5 or more buildings intended for human occupancy; an ‘‘occupied site;’’ or the right-of-way of an interstate, freeway, expressway, and other principal 4-lane arterial roadway. PHMSA proposed the definition of an ‘‘occupied site’’ to be areas or buildings occupied by 5 or more persons, which was the same as an ‘‘identified site’’ under the HCA definitions at § 192.903, except that the occupancy threshold was lowered from 20 persons to 5 persons.

The GPAC, based on a comment made by a member of the public, asked if PHMSA could provide more guidance on what a ‘‘piggable’’ line is, for the purposes of this definition. The GPAC asked whether PHMSA believed that qualifier applies to pipelines that can be fully assessed by a traditional, free-swimming ILI tool without further modification to the pipeline, and PHMSA noted during the meeting that a ‘‘piggable’’ line would be one without physical or operational modifications. The GPAC then suggested PHMSA clarify that definition in the preamble of this final rule.

GPAC members representing the public were concerned about PHMSA’s proposal during the meeting to eliminate the concept of an ‘‘occupied site’’ from the MCA definition. Industry members argued that, from a practicability standpoint, determining whether five people were in a location at any given time could be difficult, and there was significant overlap between ‘‘occupied sites’’ and the class locations that would need to be assessed per the proposal. The GPAC discussed whether some of these sites would be included within an operator’s HCA identification program already and, if not, whether operators would be able to otherwise incorporate ‘‘occupied sites’’ into their identification and assessment programs.

Several GPAC members discussed whether PHMSA should create a database or provide other guidance on which highways should be included in the MCA definition for consistency between PHMSA, State regulators, and operators. Those comments regarding highways were made following a public comment asking whether certain elevated highways needed to be included.

Following the discussion, the GPAC voted 10–0 that the MCA definition was technically feasible, reasonable, cost-effective, and practicable if PHMSA

[84] A ‘‘potential impact circle’’ is defined under § 192.903 as ‘‘a circle of radius equal to the potential impact radius,’’ where the ‘‘potential impact radius’’ is the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property.

changed the highway description to remove the reference to ''rights-of-way'' and added language so that the highway description includes ''any portion of the paved surface, including shoulders;'' clarified that highways with 4 or more lanes are included within the definition; discussed in the preamble what the definition of ''piggable'' is; and worked with the Federal Highway Administration to provide operators with clear information and discuss it in the preamble of this final rule. Additionally, the GPAC recommended PHMSA modify the term ''occupied sites'' in the definition by removing ''5 or more persons'' and the occupancy timeframe of 50 days, and tie the requirement into the HCA survey for ''identified sites'' as discussed by members and PHMSA at the meeting. Such identification could be made through publicly available databases and class location surveys, and PHMSA was to consider the sites and enforceability per direction by the committee members.

Assessments Outside of HCAs (§ 192.710)

In the NPRM, PHMSA proposed to require operators perform integrity assessments of certain pipelines outside of HCAs. Specifically, operators would perform an initial assessment within 15 years and periodic assessments 20 years thereafter of pipelines in Class 3 and Class 4 locations as well as piggable pipelines in newly-defined ''moderate consequence areas'' as discussed above.

The GPAC, based on a public comment during the meeting, questioned whether the timeframes for the initial assessment and periodic assessments were appropriate. Members debated shortening the time frames and suggested a few timeframes that could be based on a risk-based prioritization and taking into account timeframes for HCA assessments.

Following the discussion, the GPAC voted 10–0 that the provisions related to assessments outside of HCAs were technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that direct assessment can be used as an assessment method only if appropriate for the threat being assessed but cannot be used to assess threats for which direct assessment is not suitable; revised the initial assessment and reassessment intervals from 15 years and 20 years, respectively, to 14 years and 10 years, respectively, and with a risk-based prioritization; revised the applicability requirements to apply to lines with MAOPs of 30 percent SMYS or greater; and removed the provisions related to low-stress assessments.

MAOP Reconfirmation (§ 192.624)

In the NPRM, PHMSA proposed a testing regime for (1) pipelines in HCAs, Class 3 or Class 4 locations, or ''piggable'' MCAs that experienced a reportable in-service incident due to certain types of defects since its most recent successful subpart J pressure test, (2) pipelines in HCAs or Class 3 or Class 4 locations that lacked the traceable, verifiable, and complete pressure test records necessary to substantiate the current MAOP, and (3) pipelines in HCAs, Class 3 or Class 4 locations, or piggable MCAs where the operator established the MAOP using the ''grandfather'' clause pursuant to § 192.619(c). PHMSA proposed operators of these pipelines re-confirm the MAOP of those pipelines by choosing and executing one of a variety of methods. Those methods are discussed in more detail in individual sections below.

MAOP Reconfirmation Scope and Completion Date

During the discussion on MAOP reconfirmation, some GPAC members suggested PHMSA revise the applicability of the provisions to remove pipeline segments with prior crack or seam incidents, as those issues would be dealt with in an operator's IM program. Certain committee members recommended PHMSA restrict the scope of the MAOP reconfirmation provisions to pipeline segments with MAOPs of 30 percent SMYS or greater. These members argued that threshold was explicit in the congressional mandate as it pertained to previously untested pipe, and that it was based on the concept that lower-stress lines leak rather than rupture. Members further suggested that the benefit in addressing low-stress lines was not commensurate with the cost of doing so. Other committee members supported retaining the scope of PHMSA's proposals in the NPRM in order to address specific NTSB recommendations.

Following the discussion, the committee voted 13–0 that the provisions related to the scope for MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA removed pipelines with previous reportable incidents due to crack defects from the applicability paragraph; addressed pipeline segments with crack incident history in a new paragraph under the IM requirements; withdrew the definitions for ''modern pipe,'' ''legacy pipe,'' and ''legacy construction techniques;'' revised a reference to necessary records within the applicability paragraph to refer to records needed for MAOP determination and not subpart J pressure test records; and revised the applicability of the requirements for grandfathered lines to apply only to those lines with MAOPs of 30 percent or greater of SMYS. The committee also recommended PHMSA review the costs and benefits of making the requirements applicable to Class 3 and Class 4 non-HCA pipe operating below 30 percent SMYS.

As for the completion date for the MAOP reconfirmation requirements, the GPAC voted 13–0 that the related provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA addressed how the completion plan and completion dates required by the section would apply to pipelines that currently do not meet the applicability conditions but may in the future. The committee suggested PHMSA could add a phrase stating that operators must complete all actions required by the section on 100 percent of the applicable pipeline mileage 15 years after the effective date of the rule or, as soon as practicable but not to exceed 4 years after the pipeline segment first meets the applicability conditions, whichever date is later. The GPAC also recommended that PHMSA consider a waiver or no-objection procedure for extending that timeline past 4 years, if necessary.

MAOP Reconfirmation: Methods 1 and 2 (Pressure Test and Pressure Reduction)

In the NPRM, PHMSA proposed six methods an operator could use if needing to reconfirm MAOP. Method 1, a hydrostatic pressure test, would be conducted at 1.25 times MAOP or the MAOP times the class location test factor, whichever is greater. PHMSA proposed operators use a ''spike'' test method on pipeline segments with reportable in-service incidents due to known manufacturing or construction issues, and PHMSA also proposed operators estimate the remaining life of pipeline segments with crack defects. Method 2, a pressure reduction, would allow operators to reduce the pipeline segment's MAOP to the highest operating pressure divided by 1.25 times MAOP or the class location test factor times MAOP, whichever is greater. Similar to Method 1, PHMSA proposed operators taking a pressure reduction to reconfirm MAOP be required to estimate the remaining life of pipeline segments with crack defects.

The GPAC members representing the industry argued that a ''spike'' test is more appropriate to include under IM requirements and that it is not appropriate for MAOP reconfirmation. During the meeting, PHMSA noted that if the scope of the MAOP reconfirmation provisions was to be revised to delete lines with crack-like defects, the spike test requirement would not be needed. However, PHMSA would expect the spike test provisions to be utilized when otherwise required by the regulations. GPAC members also suggested adding language to address material properties verification requirements with respect to the information that is needed to conduct a pressure test. At the meeting, PHMSA suggested that the GPAC consider explicitly requiring that any information an operator does not have to perform a successful pressure test in accordance with subpart J (or that is not documented in traceable, verifiable, and complete records) be verified in accordance with the material properties verification provisions.

Following the discussion, the GPAC voted 12–0 that the provisions related to the pressure test method for MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA deleted the spike hydrostatic testing component for pipelines with suspected crack defects and referred to subpart J more broadly instead of certain sections within subpart J. The GPAC also recommended that if the pressure test segment does not have traceable, verifiable, and complete MAOP records, operators should use the best available information upon which the MAOP is currently based to perform the pressure test. The committee recommended PHMSA require operators of such pipeline segments add those segments to its plan for opportunistically verifying material properties in accordance with the material properties verification requirements, noting that most pressure tests will present at least two opportunities for material properties verification at the test manifolds.

As for the pressure reduction method of MAOP reconfirmation, the GPAC voted 12–0 that the related provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA increased the look-back period from 18 months to 5 years and removed the requirement for operators to perform fracture mechanics analysis on those pipeline segments where the pressure is being reduced to reconfirm the MAOP.

MAOP Reconfirmation: Method 3 (Engineering Critical Assessment and Fracture Mechanics)

In the NPRM, PHMSA proposed allowing operators to use an engineering critical assessment (ECA) analysis in conjunction with an ILI assessment to reconfirm a pipeline segment's MAOP where the segment's MAOP would be based upon the lowest predicted failure pressure (PFP) of the segment. This method would require specific technical documentation and material properties verification, and it would require operators analyze crack, metal loss, and interacting defects remaining in the pipe, or that could remain in the pipe, to determine the PFP. The pipeline segment's MAOP would then be established at the lowest PFP divided by 1.25 or by the applicable class location factor listed under the MAOP determination provisions, whichever of those derating factors is greater.

Most of the GPAC discussion on this portion of MAOP reconfirmation related to the specific values used in the fracture mechanics analysis portion of the ECA and whether those requirements would best be located in a section independent from the MAOP reconfirmation requirements. During the meetings, PHMSA noted it would consider creating a stand-alone fracture mechanics section that could be referenced when the procedure is needed or required by other sections of the regulations. PHMSA clarified that fracture mechanics would be needed in the context of MAOP reconfirmation only for the ECA method and ''other technology'' usage under Method 6 where the applicable pipeline segments have cracks or crack-like defects.

Following the discussion, the GPAC voted 12–0 that the provisions related to the ECA method of MAOP reconfirmation and fracture mechanics were technically feasible, reasonable, cost-effective, and practicable if PHMSA moved the fracture mechanics requirements to a stand-alone section in the regulations. The GPAC recommended the section not specify when, or for which pipeline segments, fracture mechanics analysis would be required, but instead provide a procedure by which operators needing to perform fracture mechanics analysis could do so.

The GPAC recommended several changes to the fracture mechanics requirements, including striking cross-references to the MAOP reconfirmation requirements and spike hydrostatic testing requirements, as well as striking the sensitivity analysis requirements and replacing them with a requirement that operators account for model inaccuracies and tolerances. Additionally, the GPAC recommended PHMSA add a paragraph specifying that any records created through the performance of a fracture mechanics analysis must be retained.

There were several technical GPAC recommendations related to the use of Charpy V-notch toughness values in the fracture mechanics analysis. Specifically, the GPAC recommended operators have the ability to use a conservative Charpy V-notch toughness value based on the sampling requirements of the material properties verification provisions, and that operators could use Charpy V-notch toughness values from similar or the same vintage pipe until the properties are obtained through an opportunistic testing program. Further, the GPAC recommended that the default Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) of 13-ft.-lbs. (body) and 4-ft.-lbs. (seam) only apply to pipe with suspected low-toughness properties or unknown toughness properties. Additionally, the GPAC recommended PHMSA include a requirement for operators of pipeline segments with a history of leaks or failures due to cracks to work diligently to obtain toughness data if unknown and use Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) of 5-ft.-lbs. (body) and 1-ft.-lbs. (seam) in the interim. Further, the GPAC suggested PHMSA allow operators to request the use of different default Charpy V-notch toughness values via a 90-day notification to PHMSA.

For the ECA method itself, the committee recommended PHMSA add a requirement to verify material properties in accordance with the material properties verification requirements if the information needed to conduct an ECA is not documented in traceable, verifiable, and complete records. Further, the GPAC recommended that PHMSA not include default Charpy V-notch toughness values or other technical fracture mechanics requirements in the ECA method, as those items would be specified in the new stand-alone fracture mechanics section. Similarly, the GPAC recommended removing ILI tool performance specifications and replacing them with a requirement to verify tool performance using unity plots or equivalent technologies.

MAOP Reconfirmation: Methods 4, 5, and 6 (Pipe Replacement, Small-Diameter & Potential Impact Radius Pressure Reduction, and Other Technology)

In the NPRM, PHMSA proposed three additional methods operators could use to reconfirm a pipeline's MAOP. Method 4, pipe replacement, would require operators to replace pipe for which they have inadequate records or pipe that was not previously tested due to the grandfather clause in § 192.619(c). Method 5, as proposed, was applicable to low-stress, small diameter, and small potential impact radius (PIR) lines,[85] and would require operators to take a 10 percent pressure cut as well as perform more frequent patrols and leak surveys. Method 6, ''other technology,'' would allow operators to use an alternative method, with notification to PHMSA, to reconfirm the MAOP of their applicable pipeline segments.

The GPAC had no major comments regarding Method 4, pipe replacement. For Method 5, GPAC members representing the industry questioned the need for the compensatory safety measures, such as the additional patrols and leak surveys, in conjunction with the 10 percent pressure reduction. They also supported public comments that promoted expanding the applicability of Method 5 beyond the prescribed pipe diameter of less than or equal to 8 inches and the operating pressure of below 30 percent SMYS. During the meeting, PHMSA noted it could drop the diameter and operating pressure requirements from the applicability and use the prescribed PIR of 150 feet or less as a proxy for those risk factors. Additionally, PHMSA noted it would expand the look-back period to 5 years to be consistent with committee and public comments regarding the pressure reduction method (Method 2) of MAOP reconfirmation discussed earlier. With regard to the ''other technology'' method, committee members suggested using the notification procedure developed for the material properties verification requirements, and PHMSA acknowledged it could be included here as well.

Following the discussion, the committee voted 11–0 that the provisions related to the pipe replacement, pressure reduction for small PIR and diameter lines, and ''other technology'' methods of MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA made certain changes. For Method 4, pipe replacement, the committee had no significant comments or changes. For Method 5, the small PIR and diameter pressure reduction method, the GPAC recommended PHMSA delete the size and pressure criteria, limiting the requirement to those lines with a PIR of 150 feet or less; remove the external corrosion direct assessment, crack analysis program, odorization, and fracture mechanics analysis requirements; and change the frequency of patrols and surveys to 4 times per year in Class 1 and Class 2 locations and 6 times per year in Class 3 and Class 4 locations. For Method 6, the ''other technology'' method, the GPAC recommended PHMSA incorporate the same 90-day notification and objection procedure the GPAC approved for the material properties verification requirements.

MAOP Reconfirmation: Recordkeeping and Notification

The GPAC also voted on the notification procedure and recordkeeping requirements of the MAOP reconfirmation requirements. As there were no substantial GPAC comments on these issues, the GPAC voted 11–0 that the provisions are technically feasible, reasonable, cost-effective, and practicable if PHMSA provided guidance regarding what ''traceable, verifiable, and complete'' records are in the preamble, and if the notification procedure is retained as it was proposed in the NPRM, but incorporating the same 90-day notification and objection procedure the committee approved for the material properties verification requirements into any notification required under the MAOP reconfirmation requirements.

Other MAOP Amendments (§§ 192.503, 192.605(b)(5), 192.619(a)(2), 192.619(a)(4), 192.619(e), 192.619(f))

PHMSA presented to the committee issues related to other portions of MAOP determination[86] that had cross-references to MAOP reconfirmation methods or other areas of the proposed regulations. More specifically, the GPAC was to consider recommending PHMSA eliminate duplications in scope between the MAOP determination provisions and the MAOP reconfirmation provisions, and eliminate a duplicative revision to the subpart J pressure test general requirements that was referenced adequately elsewhere in the proposal. PHMSA also proposed that the establishment of MAOP under § 192.619 should rely on traceable, verifiable, and complete records, and therefore cross-referenced the material properties verification provisions with the MAOP determination provisions. Similarly, PHMSA added a paragraph to the existing MAOP determination provisions to more clearly specify that operators must have records to substantiate the MAOP of their pipeline segments. To address an NTSB recommendation from the PG&E incident, PHMSA also proposed requiring that the MAOP pressure limitation factor specified in the MAOP determination section of the regulations for Class 1 pipeline segments be based on the subpart J test pressure divided by 1.25, whereas the existing requirement was the test pressure divided by 1.1. Finally, PHMSA proposed adding a clarification that the requirement for overpressure protection applied to pipeline segments where the MAOP was established using one of the six methods under MAOP reconfirmation. However, PHMSA noted in response to public comment that the clarification seemed to be overly confusing and should be withdrawn.

The GPAC reviewed and discussed PHMSA's proposed changes to the other MAOP-related provisions, voting 12–0 that the provisions are technically feasible, reasonable, cost-effective, and practicable if PHMSA considered editorially restructuring the applicability of the MAOP determination provisions; clarifying that the recordkeeping requirements specified under MAOP determination only apply to onshore, steel, gas transmission pipelines; and clarifying that the MAOP recordkeeping requirements are not retroactive. The GPAC suggested this be clarified by stating existing records for pipelines installed on or before the effective date of the rule must be kept for the life of the pipeline, that pipelines installed after the effective date of the rule must make and retain records as required for the life of the pipeline, and that MAOP records are required for any pipeline placed in service after the effective date of the rule. The GPAC noted that other sections, including the MAOP reconfirmation and material properties verification requirements, would require when and for which pipeline segments where MAOP records are not documented in a traceable, verifiable, and complete manner would need to be verified.

Changes From the GPAC Recommendations

In this final rule, PHMSA considered the recommendations of the GPAC and adopted them as PHMSA deemed appropriate. However, there were recommendations from the GPAC that PHMSA considered but did not adopt. To summarize, the major changes PHMSA made in this rule that deviate from the GPAC recommendations are as follows:

(1) When discussing the other proposed issues related to the MAOP requirements, the GPAC recommended

[85] These lines would be lines operating below 30 percent SMYS with diameters of 8 inches or less and PIRs of 150 feet or less.

[86] See § 192.619.

PHMSA consider moving § 192.619(e) to be a subsection of § 192.619(a) and consider referencing section § 192.624 in § 192.619(a). PHMSA did not implement this recommendation because MAOP reconfirmation for grandfathered segments is not applicable for new pipeline segments.

(2) When considering the IM clarifications at § 192.917, the GPAC recommended PHMSA consider removing the term ''hydrostatic'' from the testing requirements at § 192.917(e)(3), which deals with manufacturing and construction defects, and allow other authorized testing procedures. PHMSA is not implementing this recommendation because allowing pneumatic tests would be a safety concern to the public and operating personnel.

(3) When discussing the assessment requirements for non-HCAs under proposed § 192.710, the GPAC recommended PHMSA change the ''discovery of condition'' period allotted from 180 to 240 days. PHMSA is not implementing this suggestion from the GPAC and is retaining the 180-day timeframe for operators to determine whether a condition presents a potential threat to the integrity of the pipeline.

(4) PHMSA added a notification requirement for the use of other technology under the non-HCA assessment requirements at § 192.710. While the GPAC did not specifically request PHMSA make this change, the GPAC was generally supportive of incorporating the notification procedure the committee agreed to under the proposed material properties verification requirements for other applications.

(5) Regarding the requirements for the scope of MAOP reconfirmation, the GPAC recommended PHMSA review the costs and benefits of including Class 3 and Class 4 pipelines not located in HCAs and that operate at less than 30 percent SMYS. PHMSA did consider this as an alternative in the RIA but chose not to move forward with the proposal as suggested as it is outside the scope of the mandate.

(6) Regarding the MCA definition, the GPAC recommended PHMSA consider modifying the term ''occupied sites'' within the definition by removing reference to ''5 or more persons'' and the timeframe of 50 days and tying the requirement for identifying occupied sites to the HCA ''identified sites'' survey requirement as discussed by members and PHMSA at the meeting. In this final rule, PHMSA chose to delete the term ''occupied sites'' from the MCA definition and from the general definitions section of part 192.

(7) PHMSA moved the specific ECA requirements outside of the MAOP reconfirmation section into a new stand-alone § 192.632. The MAOP reconfirmation requirements regarding the ECA method at § 192.624(c)(3) and the ECA requirements in § 192.632 will cross-reference each other. PHMSA made this change to streamline the MAOP reconfirmation provisions and improve the readability of the requirements. No substantive changes were made to the procedure in connection with this reorganization; this was a stylistic change only.

V. Section-by-Section Analysis

§ 191.23 Reporting Safety-Related Conditions

Section 23 of the 2011 Pipeline Safety Act requires operators to report each exceedance of MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. On December 21, 2012, PHMSA published advisory bulletin ADB–2012–11, which advised operators of their responsibility under section 23 of the 2011 Pipeline Safety Act to report such exceedances. PHMSA is revising § 191.23 to codify this statutory requirement.

§ 191.25 Filing Safety-Related Condition Reports

Section 23 of the 2011 Pipeline Safety Act requires operators to report each exceedance of the MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. As described above, PHMSA is revising § 191.23 to codify this requirement. Section 191.25 is also revised to make conforming edits and comply with the mandatory 5-day reporting deadline specified in section 23 of the 2011 Pipeline Safety Act.

§ 192.3 Definitions

Section 192.3 provides definitions for various terms used throughout part 192. In support of other regulations adopted in this final rule, PHMSA is amending the proposed definition of ''*Moderate consequence area.*'' This change will define this term as it is used throughout part 192.

The definition of a ''*moderate consequence area,*'' or MCA, is based on similar methodology used to define ''*high consequence area,*'' or HCA in § 192.903. Moderate consequence areas will define the subset of non-HCA locations where integrity assessments are required (§ 192.710) and where MAOP reconfirmation is required (§ 192.624). The criteria for determining MCA locations differs from the criteria currently used to identify HCAs in that the threshold for buildings intended for human occupancy located within the potential impact radius is lowered from 20 to 5, and identified sites are excluded. In response to NTSB recommendation P–14–01, which was issued as a result of the incident near Sissonville, WV, the MCA definition also includes locations where interstate highways, freeways, expressways, and other principal 4-or-more-lane arterial roadways are located within the potential impact radius.

PHMSA is also adopting a definition of an ''*engineering critical assessment,*'' as that term will be used in §§ 192.624 and 192.632. More specifically, the ECA is a documented analytical procedure that operators can use to determine the maximum tolerable size for pipeline imperfections based on the MAOP of the particular pipeline segment. Operators can use an ECA in conjunction with an ILI inspection as one of the methods to reconfirm MAOP, if required.

§ 192.5 Class Locations

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that an important aspect of compliance with this requirement is to assure that pipeline class location records are complete and accurate. This final rule adds a new paragraph, § 192.5(d), to require each operator of transmission pipelines to maintain records documenting the current class location of each pipeline segment and demonstrating how an operator determined each current class location in accordance with this section.

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

Section 192.7 lists documents that are incorporated by reference in part 192. PHMSA is making conforming amendments to § 192.7 in the rule text to reflect other changes adopted in this final rule.

§ 192.9 What requirements apply to gathering lines?

This final rule codifies new standards for gas transmission pipelines, most of which are not intended to be applied to gas gathering pipelines. PHMSA is making conforming amendments to § 192.9 to clarify which provisions apply only to gas transmission pipelines and not to gas gathering pipelines.

§ 192.18 How To Notify PHMSA

This final rule allows operators to notify PHMSA of proposed alternative approaches to achieving the objective of the minimum safety standards in several different regulatory sections. These notification procedures for alternative actions are comparable to the existing notification requirements in subpart O for the integrity management regulations. Because PHMSA is expanding the use of notifications to pipeline segments for which subpart O does not apply (*i.e.,* to non-HCA pipeline segments), PHMSA is adding a new § 192.18 in subpart A that contains the procedure for submitting such notifications for any pipeline segment.

§ 192.67 Records: Material Properties

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline material properties records are complete and accurate. This final rule moves the original § 192.67 to § 192.69 and adds in its place a new § 192.67 that requires each operator of gas transmission pipelines installed after the effective date of this final rule to collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured. The physical characteristics an operator must keep documented include diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition. These requirements also apply to any new materials or components that are put on existing pipelines. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. These recordkeeping requirements apply to offshore gathering lines and Type A gathering lines in accordance with § 192.9.

Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.69 Storage and Handling of Plastic Pipe and Associated Components

Previous § 192.67, titled ''Storage and handling of plastic pipe and associated components,'' was created as a part of the Plastic Pipe rule, which was published on November 20, 2018 (83 FR 58716). PHMSA is redesignating that section in this final rule to a new § 192.69. No other changes have been made to the section.

§ 192.127 Records: Pipe Design

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipe design records are complete and accurate. For pipelines installed after the effective date of this final rule, this final rule adds a new § 192.127 to require each operator of gas transmission pipelines to collect or make, and retain for the life of the pipeline, records documenting pipe design to withstand anticipated external pressures and determination of design pressure for steel pipe. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.150 Passage of Internal Inspection Devices

The current pipeline safety regulations in § 192.150 require that pipelines be designed and constructed to accommodate in-line inspection devices. Prior to this rulemaking, part 192 was silent on technical standards or guidelines for implementing requirements to assure pipelines are designed and constructed for in-line inspection assessments. Previously, there was no consensus industry standard that addressed design and construction requirements for in-line inspection assessments. NACE Standard Practice, NACE SP0102–2010, ''In-line Inspection of Pipelines,'' has since been published and provides guidance on this issue in section 7. The incorporation of this standard into the Federal Pipeline Safety Regulations at § 192.150 will promote a higher level of safety by establishing consistent standards for the design and construction of pipelines to accommodate in-line inspection devices.

§ 192.205 Records: Pipeline Components

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline component records are complete and accurate. For pipelines installed after the effective date of this final rule, this final rule adds a new § 192.205 to require each operator of gas transmission pipelines to collect or make, and retain for the operational life of the component, records documenting manufacturing and testing information for valves and other pipeline components. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.227 Qualification of Welders

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline welding qualification records are complete and accurate. This final rule adds a new paragraph, § 192.227(c), to require each operator of gas transmission pipelines to make and retain records demonstrating each individual welder's qualification in accordance with this section for a minimum of 5 years following construction. This requirement will apply to pipelines installed after one year from the effective date of the rule.

§ 192.285 Plastic Pipe: Qualifying Persons To Make Joints

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that plastic pipeline qualification records are complete and accurate. This final rule adds a new paragraph, § 192.285(e), to require each operator of gas transmission pipelines to make and retain records demonstrating a person's plastic pipe joining qualifications in accordance with this section for a minimum of 5 years following construction. This requirement will apply to pipelines installed after one year from the effective date of the rule.

§ 192.493 In-Line Inspection of Pipelines

The current pipeline safety regulations at §§ 192.921 and 192.937 require that operators assess the material condition of pipelines in certain circumstances (*e.g.,* IM assessments for pipelines in HCAs) and allow the use of ILI tools for these assessments. Operators of gas transmission pipelines are required to follow the requirements of ASME/ANSI B31.8S, ''Managing System Integrity of Gas Pipelines,'' in conducting their IM activities. ASME B31.8S provides limited guidance for conducting ILI assessments. Presently, part 192 is silent on the technical standards or guidelines for performing ILI assessments or implementing these requirements. When the IM regulations were initially promulgated, there were no uniform industry standards for ILI assessments. Three related standards have since been published:

- API STD 1163–2013, ''In-Line Inspection Systems Qualification Standard.'' This Standard serves as an umbrella document to be used with and as a complement to the NACE and ASNT standards below, which are incorporated by reference in API STD 1163.
- NACE Standard Practice, NACE SP0102–2010, ''In-line Inspection of Pipelines.''
- ANSI/ASNT ILI–PQ–2005 (2010), ''In-line Inspection Personnel Qualification and Certification.''

API 1163–2013 is more comprehensive and rigorous than the current requirements in 49 CFR part 192. The incorporation of this standard into the Federal Pipeline Safety Regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software utilized by the ILI industry. The API standard addresses in detail each of the following aspects of ILI inspections, most of which are not currently addressed in the regulations:

- Systems qualification process.
- Personnel qualification.
- ILI system selection.
- Qualification of performance specifications.
- System operational validation.
- System results qualification.
- Reporting requirements.
- Quality management system.

The NACE standard covers in detail each of the following aspects of ILI assessments, most of which are not currently addressed in part 192 or in ASME B31.8S:

- Tool selection.
- Evaluation of pipeline compatibility with ILI.
- Logistical guidelines, which includes survey acceptance criteria and reporting.
- Scheduling.
- New construction (planning for future ILI in new lines).
- Data analysis.
- Data management.

The NACE standard provides a standardized questionnaire and specifies that the completed questionnaire should be provided to the ILI vendor. The questionnaire lists relevant parameters and characteristics of the pipeline section to be inspected. PHMSA determined that the consistency, accuracy, and quality of pipeline in-line inspections would be improved by incorporating the consensus NACE standard into the regulations.

The NACE standard applies to ''free swimming'' inspection tools that are carried down the pipeline by the transported product. It does not apply to tethered or remotely controlled ILI tools, which can also be used in special circumstances (*e.g.,* examination of laterals). While their use is less prevalent than free-swimming tools, some pipeline IM assessments have been conducted using tethered or remotely controlled ILI tools. PHMSA determined that many of the provisions in the NACE standard can be applied to tethered or remotely controlled ILI tools. Therefore, PHMSA is amending the Federal Pipeline Safety Regulations to allow the use of these tools, provided they comply with the applicable sections of the NACE standard.

The ANSI/ASNT standard provides for qualification and certification requirements that are not addressed by 49 CFR part 192. The incorporation of this standard into the regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes and software utilized by the ILI industry. The ANSI/ASNT standard addresses in detail each of the following aspects, which are not currently addressed in the regulations:

- Requirements for written procedures.
- Personnel qualification levels.
- Education, training and experience requirements.
- Training programs.
- Examinations (testing of personnel).
- Personnel certification and recertification.
- Personnel technical performance evaluations.

The final rule adds a new § 192.493 to require compliance with the three consensus standards discussed above when conducting ILI of pipelines.

§ 192.506 Transmission Lines: Spike Hydrostatic Pressure Test

A pressure test that incorporates a short duration ''spike'' pressure is a proven means to confirm the strength of pipe with known or suspected threats of cracks or crack-like defects (*e.g.,* stress corrosion cracking, longitudinal seam defects, etc.). Currently, part 192 does not include minimum standards for such a spike hydrostatic pressure test. This final rule adds a new § 192.506 to codify the minimum standards for performing spike hydrostatic pressure tests when operators are required to, or elect to, use this assessment method. Under the spike hydrostatic pressure test requirements, an operator may use other technologies or processes equivalent to a spike hydrostatic pressure test with justification and notification in accordance with § 192.18.

§ 192.517 Records: Tests

Section 192.517 prescribes the recordkeeping requirements for each test performed under §§ 192.505 and 192.507. PHMSA is making conforming amendments to § 192.517 to add the recordkeeping requirements for the new § 192.506.

§ 192.607 Verification of Pipeline Material Properties and Attributes: Onshore Steel Transmission Pipelines

Section 23 of the 2011 Pipeline Safety Act mandates the Secretary of Transportation to require operators of gas transmission pipelines in Class 3 and Class 4 locations and Class 1 and Class 2 locations in HCAs to verify records to ensure the records accurately reflect the physical and operational characteristics of the pipelines and confirm the MAOP of the pipelines established by the operator (49 U.S.C. 60139). PHMSA issued Advisory Bulletin 11–01 on January 10, 2011 (76

FR 1504), and Advisory Bulletin 12–06 on May 7, 2012 (77 FR 26822), to inform operators of this requirement. Operators have submitted information in their Annual Reports (starting for calendar year 2012) indicating that a portion of transmission pipeline segments do not have adequate records to establish MAOP and that some operators do not have traceable, verifiable, and complete records that accurately reflect the physical and operational characteristics of the pipeline. Therefore, PHMSA has determined that additional regulations are needed to implement the 2011 Pipeline Safety Act. This final rule promulgates specific criteria for determining which pipeline segments must undergo examinations and tests to understand and document physical and material properties and reconfirm a proper MAOP. For operators that do not have traceable, verifiable, and complete documentation for the physical pipeline characteristics and attributes of a pipeline segment, PHMSA is adding a new § 192.607 that contains the procedure for verifying and documenting pipeline physical properties and attributes that are not documented in traceable, verifiable, and complete records and to establish standards for performing these actions. For operators of certain pipelines lacking the necessary records to substantiate MAOP, PHMSA is also adding § 192.624, which provides operators several methods for reconfirming a pipeline segment's MAOP.

The new material properties verification requirements at § 192.607 include the scope of information needed and the methodology for verifying material properties and attributes of pipelines. The most difficult information to obtain, from a technical perspective, is the strength of the pipeline's steel. Conventional techniques to obtain that data would include cutting out a piece of pipe and destructively testing it to determine the yield and ultimate tensile strength. In this final rule, PHMSA is providing operators with flexibility by allowing the use of non-destructive techniques that have been validated to produce accurate results for the grade and type of pipe being evaluated (see § 192.624).

Another issue regarding material properties verification is the cost associated with excavating the pipeline to verify material properties and determining how much pipeline needs to be exposed and tested to have assurance of the accuracy of the verification. PHMSA addresses these issues within this final rule by specifying that operators can take advantage of opportunities when the pipeline is already being exposed, such as when maintenance activity is occurring and when anomaly repairs are being made, to verify material properties that are not documented in traceable, verifiable, and complete records. For example, PHMSA considers excavations associated with the direct examination of anomalies, pipeline relocations at road crossings and river or stream crossings, pipe upgrades for class location changes, pipe cut-outs for hydrostatic pressure tests, and excavations where pipe is replaced due to anomalies to be opportunities to perform material properties verification. Over time, pipeline operators will develop a substantial set of traceable, verifiable, and complete material properties data, which will provide assurance that material properties are reliably known for the population of segments that did not have pipeline physical properties and attributes documented in traceable, verifiable, and complete records previously. Through this final rule, PHMSA is requiring that operators continue this opportunistic material properties verification process until the operator has completed enough verifications to obtain a high level of confidence that only a small percentage of pipeline segments have physical pipeline characteristics and attributes that are not verified or are otherwise inconsistent with all available information or operators' past assumptions. This final rule specifies the number of excavations required for operators to achieve this level of confidence.

Operators may use an alternative sampling approach that differs from the sampling approach specified in the requirements if they notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.

Requirements are also included in the material properties verification section to ensure that operators document the results of the material properties verification process in records that must be retained for the life of the pipeline.

§ 192.619 Maximum Allowable Operating Pressure: Steel or Plastic Pipelines

The NTSB report on the PG&E incident included a recommendation (P–11–15) that PHMSA amend its regulations so that manufacturing-and construction-related defects can only be considered ''stable'' if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP. This final rule revises the test pressure factors in § 192.619(a)(2)(ii) to correspond to at least 1.25 times MAOP for pipelines installed after the effective date of this rule.

The NTSB also recommended repealing § 192.619(c), commonly referred to as the ''grandfather clause,'' and requiring that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (recommendation P–11–14). Similarly, section 23 of the 2011 Pipeline Safety Act requires that selected pipeline segments in certain locations with previously untested pipe (*i.e.,* the MAOP is established under § 192.619(c)) or without MAOP records be tested with a pressure test or equivalent means to reconfirm the pipeline's MAOP. These requirements are addressed in the new § 192.624 and are described in more detail in the following section. This final rule also makes conforming changes to § 192.619 to require that operators of pipeline segments to which § 192.624 applies establish and document the segment's MAOP in accordance with § 192.624.

§ 192.624 Maximum Allowable Operating Pressure Reconfirmation: Onshore Steel Transmission Pipelines

Section 23 of the 2011 Pipeline Safety Act requires the verification of records for pipe in Class 3 and Class 4 locations, and high-consequence areas in Class 1 and Class 2 locations, to ensure they accurately reflect the physical and operational characteristics of the pipelines and confirm the established MAOP of the pipelines. Operators have submitted information in annual reports (beginning in calendar year 2012) indicating that some gas transmission pipeline segments do not have adequate material properties records or testing records to confirm physical and operational characteristics and to establish MAOP. For these pipelines, the 2011 Pipeline Safety Act requires that PHMSA promulgate regulations to require operators to reconfirm MAOP as expeditiously as economically feasible. The statute also requires PHMSA to issue regulations that require previously untested pipeline segments located in HCAs and operating at greater than 30 percent SMYS be tested to confirm the material strength of the pipelines. Such tests must be performed by pressure testing or other methods determined by the Secretary to be of equal or greater effectiveness.

As a result of its investigation of the PG&E incident, the NTSB issued two related recommendations. NTSB recommended that PHMSA repeal § 192.619(c), commonly referred to as the ''grandfather clause,'' and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (P–11–14). The NTSB also recommended that PHMSA amend the Federal Pipeline Safety Regulations so that manufacturing- and construction-related defects can only be considered stable if a pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP (P–11–15).

Through this final rule, PHMSA is finalizing a new § 192.624 to address these mandates and recommendations. This final rule requires that operators reconfirm and document MAOP for certain onshore steel gas transmission pipelines located in HCAs or MCAs that meet one or more of the criteria specified in § 192.624(a). More specifically, this section applies to (1) pipelines in HCAs or Class 3 or Class 4 locations lacking traceable, verifiable, and complete records necessary to establish the MAOP (per § 192.619(a)) for the pipeline segment, including, but not limited to, hydrostatic pressure test records required by § 192.517(a); and (2) pipelines where the MAOP was established in accordance with § 192.619(c), the pipeline segment's MAOP is greater than or equal to 30 percent of SMYS, and the pipeline is located in an HCA, a Class 3 or Class 4 location, or an MCA that can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''). This approach implements the mandate in the 2011 Pipeline Safety Act for pipeline segments in HCAs and Class 3 and Class 4 locations (49 U.S.C. 60139). In addition, the scope includes pipeline segments in the newly defined MCAs. This approach is intended to address the NTSB recommendations and to provide increased safety in areas where a pipeline rupture would have a significant impact on the public or the environment. Though PHMSA is subjecting certain grandfathered pipeline segments to the MAOP reconfirmation requirements of § 192.624, PHMSA is not repealing § 192.619(c) for pipeline segments located outside of HCAs, Class 3 or Class 4 locations, or MCAs that can accommodate inspection by means of instrumented ILI tools. Previously grandfathered pipelines that reconfirm MAOP using one of the methods of § 192.624 that operate above 72 percent SMYS may continue to operate at the reconfirmed pressure.

The methods to reconfirm MAOP are specified in § 192.624 and are as follows:

Method 1—Pressure test. The pressure test method as specified in section 23 of the 2011 Pipeline Safety Act. Operators choosing to pressure test must also verify material property records in accordance with § 192.607. PHMSA notes that a pressure test requires the cutout of pipe at test manifold sites and those pipe cutouts would be a prime example of pipe that could and should be tested through the material properties verification procedure, if necessary. In accordance with the statute, PHMSA determined that the following methods (2) through (6) are equally effective as a pressure test for the purposes of reconfirming MAOP.

Method 2—Pressure reduction. Derating the pipeline segment so that the new MAOP is less than the historical actual sustained operating pressure by using a pressure test safety factor of 0.80 (for Class 1 and Class 2 locations) or 0.67 (for Class 3 and Class 4 locations) times the sustained operating pressure (equivalent to a pressure test using gas or water as the test medium with a test pressure of 1.25 times MAOP for Class 1 and Class 2 locations and 1.5 times MAOP for Class 3 and Class 4 locations).

Method 3—Engineering critical assessment. An in-line inspection, previously performed pressure test, or alternative technology and engineering critical assessment process using technical analysis with acceptance criteria to establish a safety margin equivalent to that provided by a new pressure test. PHMSA organized the ECA process requirements under a new § 192.632 and established the technical requirements for analyzing the predicted failure pressure as a part of the ECA analysis in a new § 192.712. If an operator chooses the ECA method for MAOP reconfirmation but does not have any of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy V-notch toughness values, if applicable), the operator must include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

Method 4—Pipe replacement. Replacement of the pipe, which would require a new pressure test that conforms with subpart J before the pipe is placed into service.

Method 5—Pressure reduction for pipeline segments with small potential impact radii. For pipeline segments with a potential impact radius of less than or equal to 150 feet, a pressure reduction using a safety factor of 0.90 times the sustained operating pressure is allowed (equivalent to a pressure test of 1.11 times MAOP), supplemented with additional preventive and mitigative measures specified in this final rule.

Method 6—Alternative technology. Other technology that the operator demonstrates provides an equivalent or greater level of safety, provided PHMSA is notified in advance in accordance with § 192.18.

Lastly, this final rule includes a new paragraph, § 192.624(f), to clearly specify that records created while reconfirming MAOP must be retained for the life of the pipeline.

§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore Steel Transmission Pipelines

The requirements for reconfirming MAOP in the new § 192.624 include an option for operators to perform an engineering critical assessment, or ECA, to reconfirm MAOP in lieu of pressure testing and the other methods provided. The requirements for conducting such an ECA were proposed under the MAOP reconfirmation requirements at § 192.624(c)(3); however, PHMSA has moved the ECA requirements to a new, stand-alone section and cross-referenced those requirements in order to improve the readability of the MAOP reconfirmation requirements.

Operators choosing the ECA method for MAOP reconfirmation may perform an in-line inspection and a technical analysis with acceptance criteria to establish a safety margin equivalent to that provided by a pressure test. PHMSA established the technical requirements for analyzing the predicted failure pressure as a part of the ECA analysis in a new § 192.712, and those requirements are cross-referenced within this ECA process.

Although PHMSA expects that most operators will use an ECA in conjunction with in-line inspection, PHMSA would also allow operators with past, valid pressure tests to calculate the largest defects that could have survived the pressure test and analyze the postulated defects to calculate a predicted failure pressure with which to establish MAOP. This approach might be desirable for operators in certain circumstances, such as for line segments that have valid pressure test records, but that lack other records (such as material strength or pipe wall thickness) necessary to determine design pressure and establish MAOP under the existing § 192.619(a). Another situation for which operators could use this approach would be if the operator has a valid pressure test, but it was not conducted at a test pressure that was high enough to establish the current MAOP.

Operators with pressure test records meeting the subpart J test requirements may use an ECA by calculating the largest defect that could have survived the pressure test and estimating the flaw growth between the date of the test and the date of the ECA. The ECA is then performed using these postulated defect sizes. In addition, operators must calculate the remaining life of the most severe defects that could have survived the pressure test and establish an appropriate re-assessment interval in accordance with new § 192.712.

If an operator chooses to use ILI to characterize the defects remaining in the pipe segment and the ECA method for MAOP reconfirmation but does not have one or more of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy V-notch toughness values, if applicable), the operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

§ 192.710 Transmission Lines: Assessments Outside of High Consequence Areas

Section 5 of the 2011 Pipeline Safety Act requires, if appropriate, the Secretary of Transportation to issue regulations expanding IM system requirements, or elements thereof, beyond HCAs. Currently, part 192 does not contain any requirement for operators to conduct integrity assessments of onshore transmission pipelines that are not HCA segments, as defined in § 192.903, and are therefore not subject to subpart O. However, only approximately 7 percent of onshore gas transmission pipelines are located in HCAs. Through this final rule, operators are required to periodically assess Class 3 locations, Class 4 locations, and MCAs that can accommodate inspection by means of an instrumented inline inspection tool. The periodic assessment requirements under this section apply to pipelines in these locations with MAOPs greater than or equal to 30 percent of SMYS.

Industry has, as a practical matter, assessed portions of pipelines in non-HCA segments coincident with integrity assessments of HCA pipeline segments. For example, INGAA has noted in comment submissions that approximately 90 percent of Class 3 and Class 4 mileage not in HCAs are presently assessed during IM assessments. This is because, in large part, ILI or pressure testing, by their nature, assess large continuous pipeline segments that may contain some HCA segments but that could also contain significant amounts of non-HCA segments.

While INGAA does not represent all pipeline operators subject to part 192, it does represent the majority of gas transmission operators. PHMSA has determined that, given this level of assessment, it is appropriate and consistent with industry direction to codify requirements for operators to periodically assess certain gas transmission pipelines outside of HCAs to monitor for, detect, and remediate pipeline defects and anomalies. Additionally, to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while minimizing the cost of identifying such locations, PHMSA is basing the requirements for identifying those locations on processes already being implemented by pipeline operators. More specifically, the MCA definition assumes a similar process used for identifying HCAs, with the exception that the threshold for buildings intended for human occupancy located within the potential impact circle is reduced from 20 to 5.

Because significant non-HCA pipeline mileage has been previously assessed in conjunction with the regular assessment of HCA pipeline segments, PHMSA is allowing operators to count those prior assessments as compliant with the new § 192.710 for the purposes of assessing non-HCAs if those assessments were conducted, and threats remediated, in conjunction with an integrity assessment required by subpart O.

This final rule also requires that the assessment required by the new § 192.710 be conducted using the same methods as adopted for HCAs (see § 192.921, below). Operators may use ''other technology'' as an assessment method, provided the operator notifies PHMSA in accordance with § 192.18.

§ 192.712 Analysis of Predicted Failure Pressure

The new requirements for reconfirming MAOP in the new § 192.624 include an option for operators to perform an engineering critical assessment, or ECA, to reconfirm MAOP in lieu of pressure testing and the other methods provided. A key aspect of the ECA analysis is the detailed analysis of the remaining strength of pipe with known or assumed defects. The current Federal Pipeline Safety Regulations in subparts I and O refer to methods for predicting the failure pressure for pipe with corrosion metal loss defects. However, the regulations are silent on performing such analysis for pipe with cracks (including crack-like defects such as selective seam weld corrosion). Therefore, in this final rule, PHMSA is inserting a new section to address the techniques and procedures for analyzing the predicted failure pressures for pipe with corrosion metal loss and cracks or crack-like defects. Examples of technically proven models for calculating predicted failure pressures include: For the brittle failure mode, the Newman-Raju Model [87] and PipeAssess PI™ software; [88] and for the ductile failure mode, Modified Log-Secant Model,[89] API RP 579–1 [90]—Level II or Level III, CorLas™ software,[91] PAFFC Model,[92] and PipeAssess PI™ software. All failure models used for the ECA analysis must be used within its technical parameters for the defect type and the pipe or weld material properties. Conforming changes are being made to applicable sections in subparts I and O to refer to this new section, for consistency, but the basic techniques are unchanged.

As a part of this section, PHMSA is including a new paragraph to address cracks and crack-like defects, which as stated above is a critical function of the ECA analysis. The ECA analysis requires the conservative analysis of any in-service cracks, crack-like defects remaining in the pipe, or the largest possible crack that could remain in the pipe, including crack dimensions (length and depth) to determine the predicted failure pressure (PFP) of each defect; the failure mode (ductile, brittle, or both) for the microstructure; the defect's location and type; the pipeline's operating conditions (including pressure cycling); and failure stress and

[87] Newman, J.C., and Raju; ''Stress Intensity Factors for Cracks in Three Dimensional Finite Bodies Subjected to Tension and Bending Loads;'' *Computational Methods in the Mechanics of Fracture;* Elsevier; 1986; pp. 311–334.

[88] Interim Report for Phase II—Task 5 of the Comprehensive Study to Understand Longitudinal ERW Seam Failures, ''Summary Report for an Integrity Management Software Tool,'' May 2017. *https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=11469.*

[89] ASTM International, ASTM STP 536, ''Failure Stress Levels of Flaws in Pressurized Cylinders,'' 1973.

[90] American Petroleum Institute and American Society of Mechanical Engineers, API 579–1/ASME FFS–1, ''Fitness-For-Service,'' Second Edition, June 2007.

[91] NACE International, NACE Corrosion 96 Paper 255, ''Effect of Stress Corrosion Cracking on Integrity and Remaining Life of Natural Gas Pipelines,'' March 1996.

[92] Pipeline Research Council International, Inc., Topical Report NG–18 No. 193, ''Development and Validation of a Ductile Flaw Growth Analysis for Gas Transmission Line Pipe,'' June 1991.

crack growth analysis to determine the remaining life of the pipeline. An ECA must use the techniques and procedures developed and confirmed through the research findings provided by PHMSA and other reputable technical sources for longitudinal seam and crack growth, such as the Comprehensive Study to Understand Longitudinal ERW Seam Research & Development study task reports: Battelle Final Reports (''Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications''—Task 1.4), Report No. 13–002 (''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams''—Subtask 2.4), Report No. 13–021 (''Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue''—Subtask 2.5), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1''—Task 4.5), which can be found online at: *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.* Operators wanting to use assumed Charpy V-notch toughness values differing from the prescribed values as a part of fracture mechanics analysis must notify PHMSA in accordance with § 192.18.

§ 192.750 Launcher and Receiver Safety

PHMSA has determined that more explicit requirements are needed for safety when performing maintenance activities that use launchers and receivers to insert and remove maintenance tools and devices, as such facilities are subject to pipeline system pressures. The current regulations for hazardous liquid pipelines at 49 CFR part 195 have, since 1981, contained such safety requirements for scraper and sphere facilities (§ 195.426). However, the regulations for natural gas pipelines do not similarly require controls or instrumentation to protect against inadvertent breaches of system integrity due to the incorrect operation of launchers and receivers for ILI tools, scraper, and sphere facilities. Accordingly, this final rule is adding a new § 192.750 to require a suitable means to relieve pressure in the barrel and either a means to indicate the pressure in the barrel or a means to prevent opening if pressure has not been relieved.

§ 192.805 Qualification Program

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.805 to refer to the new § 192.18.

§ 192.909 How can an operator change its integrity management program?

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.909 to refer to the new § 192.18.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. Accordingly, PHMSA is revising § 192.917(a)(3) to include seismicity of the area in evaluating the threat of outside force damage. To address NTSB recommendation P–11–15, PHMSA is also revising the criteria in § 192.917(e)(3) for addressing the threat of manufacturing and construction defects by requiring that a pipeline segment must have been pressure tested to a minimum of 1.25 times MAOP to conclude latent defects are stable. Section 192.917(e)(4) has additional requirements for the assessment of low-frequency ERW pipe with seam failures. It now requires usage of the appropriate technology to assess low-frequency ERW pipe, including seam cracking and selective seam weld corrosion. Pipe with seam cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.712.

Lastly, the integrity management requirements to address specific threats in § 192.917(e) include requirements for the major causes of pipeline incidents, such as corrosion, third-party damage, cyclic fatigue, manufacturing and construction defects, and electric resistance welded pipe. However, § 192.917(e) does not address cracks and crack-like defects. Therefore, PHMSA is adding a new paragraph, § 192.917(e)(6), to include specific IM requirements for addressing the threat of cracks and crack-like defects (including, but not limited to, stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) comparable to the other types of threats addressed in § 192.917(e).

§ 192.921 How is the baseline assessment to be conducted?

Section 192.921 requires that pipelines subject to the IM regulations have an integrity assessment. The current regulations allow operators to use ILI tools; pressure testing in accordance with subpart J; direct assessment for the threats of external corrosion, internal corrosion, and stress corrosion cracking; and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline. Following the PG&E incident, PHMSA determined that the baseline assessment methods should be clarified and strengthened to emphasize ILI use and pressure testing over direct assessment. At San Bruno, PG&E relied heavily on direct assessment under circumstances for which direct assessment was not effective nor appropriate for the pipeline seam type and the threats to the pipeline. Therefore, this final rule requires that direct assessment only be allowed to assess the threats for which the specific direct assessment process is appropriate.

This final rule also adds three additional assessment methods for operators to use: (1) A ''spike'' hydrostatic pressure test, which is particularly well-suited to address time-dependent threats, such as stress corrosion cracking and other cracking or crack-like defects that can include manufacturing- and construction-related defects; (2) guided wave ultrasonic testing (GWUT), which is particularly appropriate in cases where short pipeline segments, such as road or railroad crossings, are difficult to assess; and (3) excavation with direct *in situ* examination. Based upon the threat assessed, examples of appropriate non-destructive examination methods for *in situ* examination can include ultrasonic testing, phased array ultrasonic testing, inverse wave field extrapolation, radiography, or magnetic particle inspection.

The current regulations indicate that ILI tools are an acceptable assessment method for the threats that the particular ILI tool type can assess. PHMSA is clarifying in this final rule that the use of ILI tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges, and grooves), material cracking and crack-like defects (*e.g.,* stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), and hard spots with cracking. As discussed above, this final rule strengthens guidance in this area by adding a new § 192.493 to require compliance with the requirements and recommendations of API STD 1163–2005, NACE SP0102–2010, and ANSI/ASNT ILI–PQ–2005 when conducting in-line inspection of pipelines. Accordingly, PHMSA revises § 192.921(a)(1) in this final rule to require compliance with § 192.493 instead of ASME B31.8S for baseline ILI assessments for covered segments.

GWUT has been used by pipeline operators for several years. Previously, operators were required by § 192.921(a)(4) to submit a notification to PHMSA as an ''other technology'' assessment method to use GWUT. In 2007, PHMSA developed guidelines for how it would evaluate notifications for the use of GWUT. These guidelines have been effectively used for over 9 years, and PHMSA has confidence that operators can use GWUT to assess the integrity of short segments of pipe against corrosion threats. In this final rule, PHMSA is incorporating these guidelines into a new Appendix F, which is referenced in § 192.921. Therefore, operators would no longer be required to notify PHMSA to use GWUT.

ASME B31.8S, section 6.1, describes both excavation and direct *in situ* examination as specialized integrity assessment methods applicable to particular circumstances:

It is important to note that some of the integrity assessment methods discussed in para. 6 only provide indications of defects. Examination using visual inspection and a variety of nondestructive examination (NDE) techniques are required, followed by evaluation of these inspection results in order to characterize the defect. The operator may choose to go directly to examination and evaluation for the entire length of the pipeline segment being assessed, in lieu of conducting inspections. For example, the operator may wish to conduct visual examination of aboveground piping for the external corrosion threat. Since the pipe is accessible for this technique and external corrosion can be readily evaluated, performing in-line inspection is not necessary.

PHMSA is clarifying its requirements to explicitly add excavation and direct *in situ* examination as an acceptable assessment method. As previously discussed under § 192.710, PHMSA intends for operators to assess non-HCA pipe with the same methods as HCA pipe. Therefore, PHMSA has standardized the assessment methods between both the IM and non-IM sections. Operators wishing to use ''other technology'' differing from the prescribed acceptable assessment methods must notify PHMSA in accordance with § 192.18.

§ 192.933 What actions must be taken to address integrity issues?

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.933 to refer to the new § 192.18.

§ 192.935 What additional preventive and mitigative measures must an operator take?

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. Accordingly, PHMSA is revising § 192.935(b)(2) to include seismicity of the area when evaluating preventive and mitigative measures with respect to the threat of outside force damage.

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

Section 192.937 requires that operators continue to periodically assess HCA pipeline segments and periodically evaluate the integrity of each covered pipeline segment. PHMSA determined that conforming amendments would be needed to implement, and be consistent with, the changes discussed above for § 192.921. Accordingly, this final rule requires that reassessments use the same assessment methods specified in § 192.921. Operators wishing to use ''other technology'' differing from the prescribed acceptable assessment methods must notify PHMSA in accordance with § 192.18.

§ 192.939 What are the required reassessment intervals?

Section 192.939 specifies reassessment intervals for pipelines subject to IM requirements. Section 5 of the 2011 Pipeline Safety Act includes a technical correction that clarified that periodic reassessments must occur at a minimum of once every 7 calendar years, but that the Secretary may extend such deadline for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. PHMSA expects that any justification, at a minimum, must demonstrate that the extension does not pose a safety risk. In this final rule, PHMSA is codifying this technical correction.

As explained in PHMSA IM FAQ–41, the maximum interval for reassessment may be set using the specified number of calendar years. The use of calendar years is specific to gas pipeline reassessment interval years and does not alter the actual year interval requirements which appear elsewhere in the code for various inspection and maintenance requirements.

Additionally, PHMSA is revising § 192.939 to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.939 to refer to the new § 192.18.

§ 192.949 How does an operator notify PHMSA? (Removed and Reserved)

This rulemaking includes several requirements that allow operators to notify PHMSA of proposed alternative approaches to achieving the objective of the minimum safety standards. This is comparable to existing notification requirements in subpart O for pipelines subject to the IM regulations. Because PHMSA is expanding the use of notifications to pipeline segments for which subpart O does not apply (*i.e.,* to non-HCA pipeline segments), PHMSA is adding a new § 192.18 that contains the procedure for submitting such notifications. As such, § 192.949 is no longer needed and is being removed and reserved.

Appendix F to Part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

As discussed under § 192.921 above, a new Appendix F to part 192 is needed to provide specific requirements and acceptance criteria for the use of GWUT as an integrity assessment method. Operators must apply all 18 criteria defined in Appendix F to use GWUT as an integrity assessment method. If an operator applies GWUT technology in a manner that does not conform with the guidelines in Appendix F, it would be considered ''other technology'' for the purposes of §§ 192.710, 192.921, and 192.937.

VI. Standards Incorporated by Reference

A. Summary of New and Revised Standards

Consistent with the amendments in this document, PHMSA is incorporating by reference several standards as described below. Some of these standards are already incorporated by reference into the Federal Pipeline Safety Regulations and are being extended to other sections of the regulations. Other standards provide a technical basis for corresponding regulatory changes in this final rule.

• API STD 1163, ''In-Line Inspection Systems Qualification,'' Second edition, April 2013, Reaffirmed August 2018.

This standard covers the use of ILI systems for onshore and offshore gas and hazardous liquid pipelines. This includes, but is not limited to, tethered, self-propelled, or free-flowing systems for detecting metal loss, cracks, mechanical damage, pipeline geometries, and pipeline location or mapping. The standard applies to both existing and developing technologies. This standard is an umbrella document that provides performance-based requirements for ILI systems, including procedures, personnel, equipment, and associated software. The incorporation of this standard into the Federal Pipeline Safety Regulations will provide rigorous processes for qualifying the equipment, people, processes, and software used in in-line inspections.

• ANSI/ASNT ILI–PQ–2005(2010), ''In-line Inspection Personnel Qualification and Certification,'' Reapproved October 11, 2010.

This standard establishes minimum requirements for the qualification and certification of in-line inspection personnel whose jobs demand specific knowledge of the technical principles of in-line inspection technologies, operations, regulatory requirements, and industry standards as those are applicable to pipeline systems. The employer-based standard includes qualification and certification for Levels I, II, and III. The incorporation of this standard into the Federal Pipeline Safety Regulations provides for certification and qualification requirements that are not otherwise addressed in part 192 and will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software used in in-line inspections.

• NACE Standard Practice 0102–2010, ''In-Line Inspection of Pipelines,'' Revised 2010–03–13.

This standard outlines a process of related activities that a pipeline operator can use to plan, organize, and execute an ILI project, and it includes guidelines pertaining to ILI data management and data analysis. This standard is intended for individuals and teams, including engineers, O&M personnel, technicians, specialists, construction personnel, and inspectors, involved in planning, implementing, and managing ILI projects and programs. The incorporation of this standard into the Federal Pipeline Safety Regulations would promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software used in in-line inspections.

PHMSA is also extending the applicability of the following three currently incorporated-by-reference standards to new sections of the Federal Pipeline Safety Regulations:

• ASME/ANSI B16.5–2003, ''Pipe Flanges and Flanged Fittings,'' October 2004, IBR approved for § 192.607(f).

This standard covers pressure-temperature ratings, materials, dimensions, tolerances, marking, testing, and methods of designating openings for pipe flanges and flanged fittings. The standard includes requirements and recommendations regarding flange bolting, flange gaskets, and flange joints. This standard is intended for manufacturers, owners, employers, users, and others concerned with the specification, buying, maintenance, training, and safe use of valves with pressure equipment. The incorporation of this standard promotes industry best practices and operational, cost, and safety benefits.

• ASME/ANSI B31G–1991 (Reaffirmed 2004), ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' 2004, IBR approved for §§ 192.632(a) and 192.712(b).

This document provides guidance for the evaluation of metal loss in pressurized pipelines and piping systems. It is applicable to all pipelines and piping systems that are part of the scope of the transportation pipeline codes that are part of ASME B31 Code for Pressure Piping, namely: ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids; ASME B31.8, Gas Transmission and Distribution Piping Systems; ASME B31.11, Slurry Transportation Piping Systems; and ASME B31.12, Hydrogen Piping and Pipelines, Part PL.

• AGA, Pipeline Research Committee Project, PR–3–805, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,'' (December 22, 1989), IBR approved for §§ 192.632(a) and 192.712(b).

This document was developed from the Modified B31G method to allow assessment of a river bottom profile of a corroded area on a pipeline to provide more accurate predictions of the pipeline's remaining strength, and it was adapted into a software program known as RSTRENG. Pipeline operators can use RSTRENG to calculate a pipeline's predicted failure pressure and safe pressure when determining operating pressures and anomaly response times.

The incorporation by reference of ASME/ANSI B31.8S was approved for §§ 192.921 and 192.937 as of January 14, 2004. That approval is unaffected by the section revisions in this final rule.

B. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 60 standards and specifications developed and published by standard developing organizations (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices. ASTM often updates some of its more widely used standards every year, and sometimes multiple editions of standards are published in a given year.

In accordance with the National Technology Transfer and Advancement Act of 1995 (Pub. L. 104–113), PHMSA has the responsibility for determining which currently referenced standards should be updated, revised, or removed, and which standards should be added to 49 CFR parts 192, 193, and 195. Revisions to incorporated by reference materials in parts 192, 193, and 195 are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Public Law 112–90. Section 24 of that law states: ''Beginning 1 year after the date of enactment of this subsection, the Secretary may not issue guidance or a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge, on an internet website.'' 49 U.S.C. 60102(p).

On August 9, 2013, Public Law 113–30 revised 49 U.S.C. 60102(p) to replace ''1 year'' with ''3 years'' and remove the phrases ''guidance or'' and, ''on an internet website.'' This resulted in the current language in 49 U.S.C. 60102(p), which now reads as follows:

Beginning 3 years after the date of enactment of this subsection, the Secretary may not issue a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge.

On November 7, 2014, the Office of the Federal Register issued a final rule that revised 1 CFR 51.5 to require that Federal agencies include a discussion in the preamble of the final rule ''the ways the materials it incorporates by reference are reasonably available to interested parties and how interested parties can obtain the materials.'' 79 FR 66278. In relation to this rulemaking, PHMSA has contacted each SDO and has requested free public access of each standard that has been incorporated by reference. The SDOs agreed to make viewable copies of the incorporated standards available to the public at no cost. Pipeline operators interested in purchasing these standards can contact the individual and applicable standards organizations. The contact information is provided in this rulemaking action, see § 192.7.

In addition, PHMSA will provide individual members of the public temporary access to any standard that is incorporated by reference that is not otherwise available for free. Requests for access can be sent to the following email address: *PHMSAPHPStandards@dot.gov.*

VII. Regulatory Analysis and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*). Section 60102 authorizes the Secretary of Transportation to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities, as delegated to the PHMSA Administrator under 49 CFR 1.97.

PHMSA is revising the ''Authority'' entry for parts 191 and 192 to include a citation to a provision of the Mineral Leasing Act (MLA), specifically, 30 U.S.C. 185(w)(3). Section 185(w)(3) provides that ''[p]eriodically, but at least once a year, the Secretary of the Department of Transportation shall cause the examination of all pipelines and associated facilities on Federal lands and shall cause the prompt reporting of any potential leaks or safety problems.'' The Secretary has delegated this responsibility to PHMSA (49 CFR 1.97). PHMSA has traditionally complied with § 185(w)(3) through the issuance of its pipeline safety regulations, which require annual examinations and prompt reporting for all or most of the pipelines they cover. PHMSA is making this change to be consistent with and make clear its long-standing position that the agency complies with the MLA through the issuance of pipeline safety regulations.

B. Executive Orders 12866 and 13771, and DOT Regulatory Policies and Procedures

Executive Order 12866 requires agencies to regulate in the ''most cost-effective manner,'' to make a ''reasoned determination that the benefits of the intended regulation justify its costs,'' and to develop regulations that ''impose the least burden on society.'' This action has been determined to be significant under Executive Order 12866. It is also considered significant under the Regulatory Policies and Procedures of the Department of Transportation because of substantial congressional, State, industry, and public interest in pipeline safety. The final rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866 (Regulatory Planning and Review) and is consistent with the Executive Order 12866 requirements and 49 U.S.C. 60102(b)(5)–(6). Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.,* the Office of Information and Regulatory Affairs designated this rule as not a ''major rule,'' as defined by 5 U.S.C. 804(2). This final rule is considered an Executive Order 13771 regulatory action. Details on the estimated costs of this final rule can be found in the rule's RIA.

The table below summarizes the annualized costs for the provisions in the final rule. These estimates reflect the timing of the compliance actions taken by operators and are annualized, where applicable, over 21 years and discounted to 2017 using rates of 3 percent and 7 percent. PHMSA estimates incremental costs for the final requirements in Section 5 of the RIA. PHMSA finds that the other final rule requirements will not result in an incremental cost. Additionally, PHMSA did not quantify the cost savings from the material properties verification provisions under this final rule compared to the existing regulations. The costs of this final rule reflect incremental integrity assessments, MAOP reconfirmation actions, and ILI launcher and receiver upgrades; PHMSA estimates the annualized cost of this rule is $32.7 million at a 7 percent discount rate.

SUMMARY OF ANNUALIZED COSTS, 2019–2039

[$2017 thousands]

Provision	Annualized cost	
	3% Discount rate	7% Discount rate
1. MAOP Reconfirmation & Material Properties Verification	$25.9	$27.9
2. Seismicity	0	0
3. Six-Month Grace Period for Seven Calendar-Year Reassessment Intervals	0	0
4. In-Line Inspection Launcher/Receiver Safety	0.03	0.04
5. MAOP Exceedance Reports	0	0
6. Strengthening Requirements for Assessment Methods	0	0
7. Assessments Outside HCAs	5.48	4.71
8. Related Records Provisions	0	0
Total	31.4	32.7

The benefits of the final rule will depend on the degree to which compliance actions result in additional safety measures, relative to the current baseline, and the effectiveness of these measures in preventing or mitigating future pipeline releases or other incidents. For the final rule RIA, PHMSA did not monetize benefits. The rule's benefits are discussed qualitatively instead.

For more information, please see the RIA in the docket for this rulemaking.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Flexibility Fairness Act of 1996, requires Federal regulatory agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the Administrative Procedure Act unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. PHMSA prepared a FRFA which is available in the docket for the rulemaking.

D. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this final rule per the principles and criteria in Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Because this final rule would not significantly or uniquely affect the communities of the Indian tribal governments or impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

E. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. On April 18, 2016, PHMSA published an NPRM seeking public comments on the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines and gas gathering pipelines. During that time, PHMSA proposed changes to information collections that are no longer included in this final rule. PHMSA determined it would be more effective to advance a rulemaking that focuses on the mandates from the 2011 Pipeline Safety Act and split out the other provisions contained in the NPRM into two other separate rules. As such, PHMSA has removed all references to those collections previously contained in the NPRM and will submit information collection revision requests to OMB based on the requirements solely contained within this final rule.

PHMSA estimates that the proposals in this final rule will impact the information collections described below. These information collections are contained in the PSR, 49 CFR parts 190–199. The following information is provided for each information collection: (1) Title of the information collection, (2) OMB control number, (3) Current expiration date, (4) Type of request, (5) Abstract of the information collection activity, (6) Description of affected public, (7) Estimate of total annual reporting and recordkeeping burden, and (8) Frequency of collection. The information collection burden for the following information collections are estimated to be revised as follows:

1. Title: Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 09/30/2021.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. Based on the proposed revisions in this rule, 25 new recordkeeping requirements are being added to the pipeline safety regulations for owners and operators of natural gas pipelines. Therefore, PHMSA expects to add 24,609 responses and 3,740 hours to this information collection because of the provisions in this final rule.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,861,470.

Total Annual Burden Hours: 1,674,810.

Frequency of Collection: On occasion.

2. Title: Notification Requirements for Gas Transmission Pipeline Operators.

OMB Control Number: New Collection. Will Request from OMB.

Current Expiration Date: TBD.

Abstract: A person owning or operating a natural gas pipeline facility is required to provide information to the Secretary of Transportation at the Secretary's request. Based on the proposed revisions in this rule, 10 new notification requirements are being added to the pipeline safety regulations for owners and operators of natural gas pipelines. Therefore, PHMSA expects to add 721 responses and 1,070 hours because of the notification requirements in this final rule.

Affected Public: Gas Transmission operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 721.

Total Annual Burden Hours: 1,070.

Frequency of Collection: On occasion.

3. Title: Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 8/31/2020.

Abstract: This information collection covers the collection of annual report data from natural gas pipeline operators. PHMSA is revising the Gas Transmission and Gas Gathering Annual Report (form PHMSA F7 100.2–1) to collect additional information including mileage of pipe subject to the MAOP reconfirmation and MCA criteria. Based on the proposed revisions, PHMSA estimates that the Annual Report will take an additional 5 hours per report to complete to include the newly required data, increasing the burden for each report to 47 burden hours for an overall burden increase of 7,200 burden hours across all operators.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 10,852.

Total Annual Burden Hours: 83,151.

Frequency of Collection: On occasion.

4. Title: Incident for Natural Gas Pipeline Operators.

OMB Control Number: 2137–0635.

Current Expiration Date: 4/30/2022.

Abstract: This information collection covers the collection of incident report data from natural gas pipeline operators. PHMSA is revising the Gas Transmission Incident Report to have operators indicate whether incidents occur inside Moderate Consequence Areas. PHMSA does not expect there to be an increase in burden for the reporting of Gas Transmission incident data.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 301.

Total Annual Burden Hours: 3,612.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, Telephone (202) 366–4595.

Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

Those desiring to comment on these information collections should send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW, Washington, DC 20503. Comments should be submitted on or prior to October 31, 2019. Comments may also be sent via email to the Office of Management and Budget at the following address: *oira_submissions@omb.eop.gov.* OMB is required to make a decision concerning the collection of information requirements contained in this final rule between 30 and 60 days after publication of this document in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if received within 30 days of publication.

F. Unfunded Mandates Reform Act of 1995

An evaluation of Unfunded Mandates Reform Act (UMRA) considerations is performed as part of the Final Regulatory Impact Assessment. PHMSA determined that this final rule does not impose enforceable duties on State, local, or tribal governments or on the private sector of $100 million or more, adjusted for inflation, in any one year and therefore does not have implications under Section 202 of the UMRA of 1995. A copy of the RIA is available for review in the docket.

G. National Environmental Policy Act

PHMSA analyzed this final rule in accordance with the National Environmental Policy Act (42 U.S.C. 4332) and determined this action will not significantly affect the quality of the human environment. The Environmental Assessment for this final rule is in the docket.

H. Executive Order 13132: Federalism

PHMSA analyzed this final rule in accordance with Executive Order 13132 (''Federalism''). The final rule does not have a substantial direct effect on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government. This rulemaking action does not impose substantial direct compliance costs on State and local governments. The pipeline safety laws, specifically 49 U.S.C. 60104(c), prohibits State safety regulation of interstate pipelines. Under the pipeline safety law, States have the ability to augment pipeline safety requirements for intrastate pipelines regulated by PHMSA, but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility PHMSA does not regulate. It is these statutory provisions, not the rule, that govern preemption of State law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

I. Executive Order 13211

This final rule is not a ''significant energy action'' under Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use). It is not likely to have a significant adverse effect on supply, distribution, or energy use. Further, the Office of Information and Regulatory Affairs has not designated this final rule as a significant energy action.

J. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement, published on April 11, 2000 (65 FR 19476), in the **Federal Register** at: *https://www.govinfo.gov/content/FR-2000-04-11/pdf/00-8505.pdf.*

K. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN number contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

List of Subjects

49 CFR Part 191

MAOP exceedance, Pipeline reporting requirements.

49 CFR Part 192

Incorporation by reference, Integrity assessments, Material properties verification, MAOP reconfirmation, Pipeline safety, Predicted failure pressure, Recordkeeping, Risk assessment, Safety devices.

In consideration of the foregoing, PHMSA is amending 49 CFR parts 191 and 192 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 is revised to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et. seq.*, and 49 CFR 1.97.

■ 2. In § 191.23, paragraph (a)(6) is revised, paragraph (a)(10) is added, and paragraph (b)(4) is revised to read as follows:

§ 191.23 Reporting safety-related conditions.

(a) * * *

(6) Any malfunction or operating error that causes the pressure—plus the margin (build-up) allowed for operation of pressure limiting or control devices—to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility, or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG.

* * * * *

(10) For transmission pipelines only, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in the applicable requirements of §§ 192.201, 192.620(e), and 192.739. The reporting requirement of this paragraph (a)(10) is not applicable to gathering lines, distribution lines, LNG facilities, or underground natural gas storage facilities (*See* paragraph (a)(6) of this section).

(b) * * *

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report. Notwithstanding this exception, a report must be filed for:

(i) Conditions under paragraph (a)(1) of this section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; and

(ii) Any condition under paragraph (a)(10) of this section.

* * * * *

■ 3. Section 191.25 is revised to read as follows:

§ 191.25 Filing safety-related condition reports.

(a) Each report of a safety-related condition under § 191.23(a)(1) through (9) must be filed (received by the Associate Administrator) in writing within 5 working days (not including Saturday, Sunday, or Federal holidays) after the day a representative of an operator first determines that the condition exists, but not later than 10 working days after the day a representative of an operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reporting methods and report requirements are described in paragraph (c) of this section.

(b) Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in § 191.23(a)(10) for a gas transmission pipeline must be filed (received by the Associate Administrator) in writing within 5 calendar days of the exceedance using the reporting methods and report requirements described in paragraph (c) of this section.

(c) Reports must be filed by email to *InformationResourcesManager@dot.gov* or by facsimile to (202) 366–7128. For a report made pursuant to § 191.23(a)(1) through (9), the report must be headed ''Safety-Related Condition Report.'' For a report made pursuant to § 191.23(a)(10), the report must be headed ''Maximum Allowable Operating Pressure Exceedances.'' All reports must provide the following information:

(1) Name, principal address, and operator identification number (OPID) of the operator.

(2) Date of report.

(3) Name, job title, and business telephone number of person submitting the report.

(4) Name, job title, and business telephone number of person who determined that the condition exists.

(5) Date condition was discovered and date condition was first determined to exist.

(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.

(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.

(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 4. The authority citation for part 192 is revised to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et. seq.,* and 49 CFR 1.97.

■ 5. In § 192.3, the definitions for ''Engineering critical assessment (ECA)'' and ''Moderate consequence area'' are added in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Engineering critical assessment (ECA) means a documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure.

* * * * *

Moderate consequence area means:

(1) An onshore area that is within a potential impact circle, as defined in § 192.903, containing either:

(i) Five or more buildings intended for human occupancy; or

(ii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1* (see: *https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf*), and that does not meet the definition of high consequence area, as defined in § 192.903.

(2) The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either 5 or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either 5 or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

* * * * *

■ 6. In § 192.5, paragraph (d) is added to read as follows:

§ 192.5 Class locations.

* * * * *

(d) An operator must have records that document the current class location of each pipeline segment and that demonstrate how the operator determined each current class location in accordance with this section.

■ 7. Amend § 192.7 as follows:
■ a. Revise paragraph (a)(1)(ii);
■ b. Add paragraph (b)(12);
■ c. Revise paragraphs (c)(2) and (4);
■ d. Re-designate paragraphs (d) through (j) as paragraphs (e) through (k), respectively;
■ e. Add new paragraphs (d) and (h)(2); and
■ f. Revise newly redesignated paragraph (j)(1).

The revisions and additions read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

(a) * * *

(1) * * *

(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email *fedreg.legal@nara.gov* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html.*

(b) * * *

(12) API STANDARD 1163, ''In-Line Inspection Systems Qualification,'' Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for § 192.493.

(c) * * *

(2) ASME/ANSI B16.5–2003, ''Pipe Flanges and Flanged Fittings,'' October 2004, (ASME/ANSI B16.5), IBR approved for §§ 192.147(a), 192.279, and 192.607(f).

* * * * *

(4) ASME/ANSI B31G–1991 (Reaffirmed 2004), ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' 2004, (ASME/ANSI B31G), IBR approved for §§ 192.485(c), 192.632(a), 192.712(b), and 192.933(a).

* * * * *

(d) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone: 800–222–2768, website: *https://www.asnt.org/.*

(1) ANSI/ASNT ILI–PQ–2005(2010), ''In-line Inspection Personnel Qualification and Certification,'' Reapproved October 11, 2010, (ANSI/ ASNT ILI–PQ), IBR approved for § 192.493.

(2) [Reserved]

* * * * *

(h) * * *

(2) NACE Standard Practice 0102–2010, ''In-Line Inspection of Pipelines,'' Revised 2010–03–13, (NACE SP0102), IBR approved for §§ 192.150(a) and 192.493.

* * * * *

(j) * * *

(1) AGA, Pipeline Research Committee Project, PR–3–805, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,'' (December 22, 1989), (PRCI PR–3–805 (R–STRENG)), IBR approved for §§ 192.485(c); 192.632(a); 192.712(b); 192.933(a) and (d).

* * * * *

■ 8. In § 192.9, paragraphs (b), (c), and (d)(1), (2), and (6) are revised to read as follows:

§ 192.9 What requirements apply to gathering lines?

* * * * *

(b) Offshore lines. An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.150, 192.285(e), 192.493, 192.506, 192.607, 192.619(e), 192.624, 192.710, 192.712, and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.150, 192.285(e), 192.493, 192.506, 192.607, 192.619(e), 192.624, 192.710, 192.712, and in subpart O of this part. However, operators of Type A regulated onshore gathering lines in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) * * *

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines except the requirements in §§ 192.67, 192.127, 192.205, 192.227(c), 192.285(e), and 192.506;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except the requirements in § 192.493;

* * * * *

(6) Establish the MAOP of the line under § 192.619(a), (b), and (c);

* * * * *

■ 9. Section 192.18 is added to read as follows:

§ 192.18 How to notify PHMSA.

(a) An operator must provide any notification required by this part by—

(1) Sending the notification by electronic mail to *InformationResourcesManager@dot.gov;* or

(2) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, 1200 New Jersey Ave. SE, Washington, DC 20590.

(b) An operator must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate applicable pipeline segment is regulated by that State.

(c) Unless otherwise specified, if the notification is made pursuant to § 192.506(b), § 192.607(e)(4), § 192.607(e)(5), § 192.624(c)(2)(iii), § 192.624(c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv), § 192.712(e)(2)(i)(E), § 192.921(a)(7), or § 192.937(c)(7) to use a different integrity assessment method, analytical method, sampling approach, or technique (*i.e.,* ''other technology'') that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.

§ 192.67 [Redesignated as § 192.69]

■ 10. Redesignate § 192.67 as § 192.69.

■ 11. Section 192.67 is added to read as follows:

§ 192.67 Records: Material properties.

(a) For steel transmission pipelines installed after [July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with §§ 192.53 and 192.55. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.

(b) For steel transmission pipelines installed on or before July 1, 2020], if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with §§ 192.53 and 192.55, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020], if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

■ 12. Section 192.127 is added to read as follows:

§ 192.127 Records: Pipe design.

(a) For steel transmission pipelines installed after July 1, 2020], an operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with § 192.103 and documenting that the determination of design pressure for the pipe is made in accordance with § 192.105.

(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting pipe design and the determination of design pressure in accordance with §§ 192.103 and 192.105, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

■ 13. In § 192.150, paragraph (a) is revised to read as follows:

§ 192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line, must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference, *see* § 192.7).

* * * * *

■ 14. Section 192.205 is added to read as follows:

§ 192.205 Records: Pipeline components.

(a) For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.

(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

■ 15. In § 192.227, paragraph (c) is added to read as follows:

§ 192.227 Qualification of welders.

* * * * *

(c) For steel transmission pipe installed after July 1, 2021, records demonstrating each individual welder qualification at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

■ 16. In § 192.285, paragraph (e) is added to read as follows:

§ 192.285 Plastic pipe: Qualifying persons to make joints.

* * * * *

(e) For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

■ 17. Section 192.493 is added to read as follows:

§ 192.493 In-line inspection of pipelines.

When conducting in-line inspections of pipelines required by this part, an operator must comply with API STD 1163, ANSI/ASNT ILI–PQ, and NACE SP0102, (incorporated by reference, *see* § 192.7). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.

■ 18. Section 192.506 is added to read as follows:

§ 192.506 Transmission lines: Spike hydrostatic pressure test.

(a) *Spike test requirements.* Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with this section.

(1) The test must use water as the test medium.

(2) The baseline test pressure must be as specified in the applicable paragraphs of § 192.619(a)(2) or § 192.620(a)(2), whichever applies.

(3) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505.

(4) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.

(b) *Other technology or other technical evaluation process.* Operators may use other technology or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this subchapter. The notification must be made in accordance with § 192.18 and must include the following information:

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;

(2) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;

(3) Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;

(4) Assessment techniques and acceptance criteria;

(5) Remediation methods for assessment findings;

(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;

(7) Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and

(8) Evidence of a review of all procedures and assessments by a qualified technical subject matter expert.

■ 19. In § 192.517, paragraph (a) introductory text is revised to read as follows:

§ 192.517 Records: Tests.

(a) An operator must make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505, 192.506, and 192.507. The record must contain at least the following information:

* * * * *

■ 20. Section 192.607 is added to read as follows:

§ 192.607 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

(a) *Applicability.* Wherever required by this part, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this section.

(b) *Documentation of material properties and attributes.* Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (*e.g.,* yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at § 192.624(c)(3) or the fracture mechanics requirements at § 192.712 must be maintained for the life of the pipeline.

(c) *Verification of material properties and attributes.* If an operator does not have traceable, verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:

(1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.

(2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.

(3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.

(4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.

(5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.

(d) *Special requirements for nondestructive Methods.* Procedures developed in accordance with paragraph (c) of this section for verification of material properties and attributes using nondestructive methods must:

(1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;

(2) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and

(3) Use test equipment that has been properly calibrated for comparable test materials prior to usage.

(e) *Sampling multiple segments of pipe.* To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:

(1) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.

(2) For each population defined according to paragraph (e)(1) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to § 192.614, until completion of the lesser of the following:

(i) One excavation per mile rounded up to the nearest whole number; or

(ii) 150 excavations if the population is more than 150 miles.

(3) Prior tests conducted for a single excavation according to the requirements of paragraph (c) of this section may be counted as one sample under the sampling requirements of this paragraph (e).

(4) If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with § 192.18.

(5) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (e)(2) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.

(f) *Components.* For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (c) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5 (incorporated by reference, *see* § 192.7)),

(1) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.

(2) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:

(i) Larger than 2 inches in nominal outside diameter,

(ii) Material grades of 42,000 psi (Grade X–42) or greater, or

(iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(3) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.

(g) *Uprating.* The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi in accordance with § 192.107(b)(2).

■ 21. In § 192.619, the introductory text of paragraphs (a) introductory text and (a)(2) and (4) are revised and paragraphs (e) and (f) are added to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:

* * * * *

(2) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 psi (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the Table 1 to paragraph (a)(2)(ii):

TABLE 1 TO PARAGRAPH (a)(2)(ii)

Class location	Installed before (Nov. 12, 1970)	Factors,[1] segment— Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1] For offshore pipeline segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

* * * * *

(4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with § 192.607, if applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure.

* * * * *

(e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624.

(f) Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (a) through (e) of this section as follows:

(1) Operators of pipelines in operation as of [July 1, 2020 must retain any existing records establishing MAOP for the life of the pipeline;

(2) Operators of pipelines in operation as of July 1, 2020 that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with § 192.624, must retain the records reconfirming MAOP for the life of the pipeline; and

(3) Operators of pipelines placed in operation after July 1, 2020 must make and retain records establishing MAOP for the life of the pipeline.

■ 22. Section 192.624 is added to read as follows:

§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

(a) *Applicability.* Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section if either of the following conditions are met:

(1) Records necessary to establish the MAOP in accordance with § 192.619(a), including records required by § 192.517(a), are not traceable, verifiable, and complete and the pipeline is located in one of the following locations:

(i) A high consequence area as defined in § 192.903; or

(ii) A Class 3 or Class 4 location.

(2) The pipeline segment's MAOP was established in accordance with § 192.619(c), the pipeline segment's MAOP is greater than or equal to 30 percent of the specified minimum yield strength, and the pipeline segment is located in one of the following areas:

(i) A high consequence area as defined in § 192.903;

(ii) A Class 3 or Class 4 location; or

(iii) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools.

(b) *Procedures and completion dates.* Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of § 192.624(a), and for performing a spike test or material verification in accordance with §§ 192.506 and 192.607, if applicable. All actions required by this section must be completed according to the following schedule:

(1) Operators must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, 2028.

(2) Operators must complete all actions required by this section on 100% of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) (*e.g.,* due to a location becoming a high consequence area), whichever is later.

(3) If operational and environmental constraints limit an operator from meeting the deadlines in § 192.624, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with § 192.18. The notification must include an up-to-date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and

any needed temporary measures needed to mitigate the impact on safety.

(c) *Maximum allowable operating pressure determination.* Operators of a pipeline segment meeting a condition in paragraph (a) of this section must reconfirm its MAOP using one of the following methods:

(1) *Method 1: Pressure test.* Perform a pressure test and verify material properties records in accordance with § 192.607 and the following requirements:

(i) *Pressure test.* Perform a pressure test in accordance with subpart J of this part. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii).

(ii) *Material properties records.* Determine if the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).

(iii) *Material properties verification.* If any of the records required by paragraph (c)(1)(ii) of this section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with § 192.607. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with § 192.607.

(2) *Method 2: Pressure Reduction.* Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (*i.e.,* the location-specific operating pressure at each location).

(i) Where the pipeline segment has had a class location change in accordance with § 192.611, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:

(A) For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.

(B) For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 2.00.

(ii) Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is established using Method 2.

(iii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with § 192.18 no later than 7 calendar days after establishing the reduced MAOP. The notification must include the following details:

(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with § 192.712;

(C) Justification that establishing MAOP by another method allowed by this section is impractical;

(D) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance with § 192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and

(E) Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.

(3) *Method 3: Engineering Critical Assessment (ECA).* Conduct an ECA in accordance with § 192.632.

(4) *Method 4: Pipe Replacement.* Replace the pipeline segment in accordance with this part.

(5) *Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius.* Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:

(i) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (*i.e.,* the location specific operating pressure at each location);

(ii) Conduct patrols in accordance with § 192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with § 192.706 at intervals not to exceed those in the following table 1 to § 192.624(c)(5)(ii):

TABLE 1 TO § 192.624(c)(5)(ii)

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2	3½ months, but at least four times each calendar year	3½ months, but at least four times each calendar year.
(B) Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year.

(iii) Under Method 5, future uprating of the pipeline segment in accordance with subpart K is allowed.

(6) *Method 6: Alternative Technology.* Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with § 192.18. The notification must include descriptions of the following details:

(i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated;

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;

(iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;

(iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;

(v) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.712;

(vi) Operational monitoring procedures;

(vii) Methodology and criteria used to justify and establish the MAOP; and

(vii) Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.

(d) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

■ 23. Section 192.632 is added to read as follows:

§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines.

When an operator conducts an MAOP reconfirmation in accordance with § 192.624(c)(3) ''Method 3'' using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this section. The ECA must assess: Threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

(a) *ECA Analysis.* (1) The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: Diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with this paragraph are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with § 192.607. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by subpart I of this part, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by §§ 192.617, 192.710, and subpart O of this part.

(2) The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:

(i) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with § 192.712.

(ii) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI B31G (incorporated by reference, *see* § 192.7) or R–STRENG (incorporated by reference, *see* § 192.7) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth).

(iii) When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented.

(iv) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using § 192.607.

(3) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

(4) The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii).

(b) *Assessment to determine defects remaining in the pipe.* An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with paragraph (a) of this section.

(1) An operator may use a previous pressure test that complied with subpart J to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of subpart J of this part exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in

accordance with § 192.712. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a re-assessment interval in accordance with the methodology in § 192.712.

(2) Operators may use an inline inspection program in accordance with paragraph (c) of this section.

(3) Operators may use ''other technology'' if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use ''other technology'' in the ECA, it must notify PHMSA in advance of using the other technology in accordance with § 192.18. The ''other technology'' notification must have:

(i) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.

(c) *In-line inspection.* An inline inspection (ILI) program to determine the defects remaining the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking.

(1) If a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.

(2) If the pipeline has had a reportable incident, as defined in § 191.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with this section includes an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.

(3) Inline inspection must be performed in accordance with § 192.493.

(4) An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.

(5) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O of this part, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.

(6) Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in §§ 192.713 and 192.933.

(d) *Defect remaining life.* If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with § 192.712.

(e) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

■ 24. Section 192.710 is added to read as follows:

§ 192.710 Transmission lines: Assessments outside of high consequence areas.

(a) *Applicability:* This section applies to onshore steel transmission pipeline segments with a maximum allowable operating pressure of greater than or equal to 30% of the specified minimum yield strength and are located in:

(1) A Class 3 or Class 4 location; or

(2) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (*i.e.,* ''smart pig'').

(3) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.

(b) *General*—(1) *Initial assessment.* An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of § 192.710(a) (*e.g.,* due to a change in class location or the area becomes a moderate consequence area), whichever is later.

(2) *Periodic reassessment.* An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.

(3) *Prior assessment.* An operator may use a prior assessment conducted before July 1, 2020 as an initial assessment for the pipeline segment, if the assessment met the subpart O requirements of part 192 for in-line inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(2) of this section calculated from the date of the prior assessment.

(4) *MAOP verification.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) for establishing MAOP may be used as an initial assessment or reassessment under this section.

(c) *Assessment method.* The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods:

(1) *Internal inspection.* Internal inspection tool or tools capable of detecting those threats to which the

pipeline is susceptible, such as corrosion, deformation and mechanical damage (*e.g.,* dents, gouges and grooves), material cracking and crack-like defects (*e.g.,* stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;

(2) *Pressure test.* Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;

(3) *Spike hydrostatic pressure test.* A spike hydrostatic pressure test conducted in accordance with § 192.506. A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) *Direct examination.* Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

(5) *Guided Wave Ultrasonic Testing.* Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;

(6) *Direct assessment.* Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or

(7) *Other technology.* Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.

(d) *Data analysis.* An operator must analyze and account for the data obtained from an assessment performed under paragraph (c) of this section to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (*e.g.,* tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

(e) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that 180 days is impracticable.

(f) *Remediation.* An operator must comply with the requirements in §§ 192.485, 192.711, and 192.713, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

(g) *Analysis of information.* An operator must analyze and account for all available relevant information about a pipeline in complying with the requirements in paragraphs (a) through (f) of this section.

■ 25. Section 192.712 is added to read as follows:

§ 192.712 Analysis of predicted failure pressure.

(a) *Applicability.* Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.

(b) *Corrosion metal loss.* When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R–STRENG (incorporated by reference, *see* § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

(c) [Reserved]

(d) *Cracks and crack-like defects*—(1) *Crack analysis models.* When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).

(2) *Analysis for crack growth and remaining life.* If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.

(i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph (e)(2) of this section must be used.

(ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).

(iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

(3) *Cracks that survive pressure testing.* For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph (d)(1) of this section. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:

(i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in § 192.607;

(iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or

(iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.

(e) *Data.* In performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows.

(1) An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements.

(2) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator shall use conservative assumptions as follows:

(i) *Material toughness.* An operator must use one of the following for material toughness:

(A) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(B) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607;

(C) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;

(D) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or

(E) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with § 192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.

(ii) *Material strength.* An operator must assume one of the following for material strength:

(A) Grade A pipe (30,000 psi), or

(B) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.

(iii) *Pipe dimensions and other data.* Until pipe wall thickness, diameter, or other data are determined and documented in accordance with § 192.607, the operator must use values upon which the current MAOP is based.

(f) *Review.* Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.

(g) *Records.* An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:

(1) The technical approach used for the analysis;

(2) All data used and analyzed;

(3) Pipe and weld properties;

(4) Procedures used;

(5) Evaluation methodology used;

(6) Models used;

(7) Direct in situ examination data;

(8) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;

(9) Pressure test data and results;

(10) In-the-ditch assessments;

(11) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;

(12) All finite element analysis results;

(13) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;

(14) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;

(15) Safety factors used for fatigue life and/or predicted failure pressure calculations;

(16) Reassessment time interval and safety factors;

(17) The date of the review;

(18) Confirmation of the results by qualified technical subject matter experts; and

(19) Approval by responsible operator management personnel.

■ 26. Section 192.750 is added to read as follows:

§ 192.750 Launcher and receiver safety.

Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (*e.g.* inspection tools, scrapers, or spheres), if pressure has not been relieved.

■ 27. In § 192.805, paragraph (i) is revised to read as follows:

§ 192.805 Qualification Program.

* * * * *

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if an operator significantly modifies the program after the administrator or state agency has verified that it complies with this section. Notifications to PHMSA must be submitted in accordance with § 192.18.

■ 28. In § 192.909, paragraph (b) is revised to read as follows:

§ 192.909 How can an operator change its integrity management program?

* * * * *

(b) *Notification.* An operator must notify OPS, in accordance with § 192.18, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must provide notification within 30 days after adopting this type of change into its program.

■ 29. In § 192.917, paragraphs (a)(3) and (e)(2) through (4) are revised, and paragraph (e)(6) is added to read as follows:

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) * * *

(3) Time independent threats such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage to include consideration of seismicity, geology, and soil stability of the area; and

* * * * *

(e) * * *

(2) *Cyclic fatigue.* An operator must analyze and account for whether cyclic fatigue or other loading conditions (including ground movement, and suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The analysis must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the analysis together with the criteria used to determine the significance of the threat(s) to the covered segment to prioritize the integrity baseline assessment or reassessment. Failure stress pressure and crack growth analysis of cracks and crack-like defects must be conducted in accordance with § 192.712. An operator must monitor operating pressure cycles and periodically, but at least every 7 calendar years, with intervals not to exceed 90 months, determine if the cyclic fatigue analysis remains valid or if the cyclic fatigue analysis must be revised based on changes to operating pressure cycles or other loading conditions.

(3) *Manufacturing and construction defects.* An operator must analyze the covered segment to determine and account for the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. The analysis must account for the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to hydrostatic pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP, and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J pressure test. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment.

(i) The pipeline segment has experienced a reportable incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, or a construction-, installation-, or fabrication-related defect;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *Electric Resistance Welded (ERW) pipe.* If a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0 as defined in § 192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding 5 years (including abnormal operation as defined in § 192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment. Pipe with seam cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.712.

* * * * *

(6) *Cracks.* If an operator identifies any crack or crack-like defect (*e.g.,* stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) on a covered pipeline segment that could adversely affect the integrity of the pipeline, the operator must evaluate, and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar characteristics associated with the crack or crack-like defect. Similar characteristics may include operating and maintenance histories, material properties, and environmental characteristics. An operator must establish a schedule for evaluating, and remediating, as necessary, the similar pipeline segments that is consistent with the operator's established operating and maintenance procedures under this part for testing and repair.

■ 30. In § 192.921, revise paragraph (a) and add paragraph (i) to read as follows:

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917).

(1) Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible. The use of internal inspection tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (*e.g.,* stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. In addition, an operator must analyze and account for uncertainties in reported results (*e.g.,* tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool

performance) in identifying and characterizing anomalies;

(2) Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7) to justify an extended reassessment interval in accordance with § 192.939.

(3) Spike hydrostatic pressure test conducted in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and the pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.

* * * * *

(i) *Baseline assessments for pipeline segments with a reconfirmed MAOP.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a baseline assessment under this section.

■ 31. In § 192.933, paragraphs (a)(1) and (2) are revised to read as follows:

§ 192.933 What actions must be taken to address integrity issues?

(a) * * *

(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R–STRENG (incorporated by reference, *see* § 192.7); or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, an operator must notify PHMSA under § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

* * * * *

■ 32. In § 192.935, paragraph (b)(2) is revised to read as follows:

§ 192.935 What additional preventive and mitigative measures must an operator take?

* * * * *

(b) * * *

(2) *Outside force damage.* If an operator determines that outside force (*e.g.,* earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include increasing the frequency of aerial, foot or other methods of patrols; adding external protection; reducing external stress; relocating the line; or inline inspections with geospatial and deformation tools.

* * * * *

■ 33. In § 192.937, revise paragraph (c) and add paragraph (d) to read as follows:

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

* * * * *

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified on the covered segment (*see* § 192.917).

(1) *Internal inspection tools.* When performing an assessment using an in-line inspection tool, an operator must comply with the following requirements:

(i) Perform the in-line inspection in accordance with § 192.493;

(ii) Select a tool or combination of tools capable of detecting the threats to which the pipeline segment is susceptible such as corrosion, deformation and mechanical damage (*e.g.* dents, gouges and grooves), material cracking and crack-like defects (*e.g.* stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible; and

(iii) Analyze and account for uncertainties in reported results (*e.g.,* tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

(2) *Pressure test conducted in accordance with subpart J of this part.* The use of pressure testing is appropriate for threats such as: Internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test

pressures specified in table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7) to justify an extended reassessment interval in accordance with § 192.939.

(3) *Spike hydrostatic pressure test in accordance with § 192.506.* The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as: Stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, or magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927, and 192.929;

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18; or

(8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than 7 calendar years. An operator using this reassessment method must comply with § 192.931.

(d) *MAOP reconfirmation assessments.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a reassessment under this section.

■ 34. In § 192.939, paragraphs (a) introductory text, (b) introductory text, and (b)(1) are revised to read as follows:

§ 192.939 What are the required reassessment intervals?

* * * * *

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS, in accordance with § 192.18, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than 7 calendar years, the operator must, within the 7-calendar-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

* * * * *

(b) *Pipelines Operating below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS in accordance with § 192.18. The notice must include sufficient justification of the need for the extension. An operator must establish reassessment by at least one of the following—

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than 7 calendar years, an operator must conduct by the seventh calendar year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low stress reassessment in accordance with § 192.941.

* * * * *

§ 192.949 [Removed and Reserved]

■ 35. Remove and reserve § 192.949.

■ 36. Appendix F is added to read as follows:

Appendix F to Part 192–Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

This appendix defines criteria which must be properly implemented for use of guided wave ultrasonic testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered ‘‘other technology’’ as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified 90 days prior to use in accordance with §§ 192.921(a)(7) or 192.937(c)(7). GWUT in the ‘‘Go-No Go’’ mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested, or replaced prior to completing the integrity assessment on the carrier pipe.

I. *Equipment and Software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Computer software for the inspection equipment must be reviewed and updated, as required, on an annual basis, with intervals not to exceed 15 months, to support sensors, enhance functionality, and resolve any technical or operational issues identified.

II. *Inspection Range.* The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general, the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.

III. *Complete Pipe Inspection.* To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double-ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

IV. *Sensitivity.* The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than 5% of the cross sectional area (CSA).

The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

All defect indications in the ''Go-No Go'' mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

V. *Wave Frequency.* Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

VI. *Signal or Wave Type: Torsional and Longitudinal.* Both torsional and longitudinal waves must be used and use must be documented.

VII. *Distance Amplitude Correction (DAC) Curve and Weld Calibration.* The distance amplitude correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection. DAC curves provide a means for evaluating the cross-sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

VIII. *Dead Zone.* The dead zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

IX. *Near Field Effects.* The near field is the region beyond the dead zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

X. *Coating Type.* Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the pipe, then another type of assessment method must be utilized.

XI. *End Seal.* When assessing cased carrier pipe with GWUT, operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.

XII. *Weld Calibration to set DAC Curve.* Accessible welds, along or outside the pipeline segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipeline segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by a documented engineering analysis and evaluation.

XIII. *Validation of Operator Training.* Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:

A. Equipment operation,

B. field data collection, and

C. data interpretation on cased and buried pipe.

Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment. A senior-level GWUT equipment operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A senior-level GWUT equipment operator must have additional training and experience, including training specific to cased and buried pipe, with a quality control program which that conforms to Section 12 of ASME B31.8S (for availability, see § 192.7).

XIV. *Training and Experience Minimums for Senior Level GWUT Equipment Operators:*

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XV. *Equipment: Traceable from vendor to inspection company.* An operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.

XVI. *Calibration Onsite.* The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated to a different casing or pipeline segment. If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVII. *Use on Shorted Casings (direct or electrolytic).* GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (*see § 192.605*) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures.

XVIII. *Direct examination of all indications above the detection sensitivity threshold.* The use of GWUT in the ''Go-No Go'' mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe or other GWUT application. If this cannot be accomplished, then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

XIV. *Timing of direct examination of all indications above the detection sensitivity threshold.* Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

REQUIRED RESPONSE TO GWUT INDICATIONS

GWUT criterion	Operating pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50% SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of 5% CSA).	Replace or direct examination within 12 months, and instrumented leak survey once every 30 calendar days.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and maintain MAOP below the operating pressure at time of discovery.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of operating pressure at time of discovery.

Issued in Washington, DC, on September 16, 2019, under authority delegated in 49 CFR part 1.97.

Howard R. Elliott,

Administrator.

[FR Doc. 2019–20306 Filed 9–30–19; 8:45 am]

BILLING CODE 4910–60–P

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

Question:

220. Refer to Exhibit A-96, page 1. Please expand this schedule to include actual costs for each line item for each year 2018 to 2023, and forecasted for 2024 and 2025, and provide it in Excel.

Response:

Please see attachment U21490-AG-CE-0379_Pascarello_ATT_1.

Witness: Kristine A. Pascarello
Date: April 8, 2024

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No: U-21490**
Consumers Energy Company | **Exhibit: AG-12**
April 22, 2024
CECo Response to AG-CE-0379 |

MICHIGAN PUBLIC SERVICE COMMISSION			**U21490-AG-CE-0379_Pascarello_ATT_1**				Case No.:	U-21490				
Consumers Energy Company							Exhibit No.:	A-96 (KAP-4)				
Actual & Projected Gas Capital Expenditures							Page:	1 of 3				
Material Condition Program							Witness:	KAPascarello				
($000)							Date:	December 2023				
		(a)						(b)	(c)	(d)	(e)	(f)
								Capital Expenditures				
			Historical	**Historical**	**Historical**	**Historical**	**Historical**	**Preliminary Actual**	**Projected Bridge Year**			**Projected Test Year**
Line No.		**Program Description**	**12 Mos Ended 12/31/2018**	**12 Mos Ended 12/31/2019**	**12 Mos Ended 12/31/2020**	**12 Mos Ended 12/31/2021**	**12 Mos Ended 12/31/2022**	**12 Mos Ended 12/31/2023**	**12 Mos Ending 12/31/2023**	**9 Mos Ending 9/30/2024**	**21 Mos Ending 9/30/2024**	**12 Mos Ending 9/30/2025**
1		EIRP - Distribution	**86,789**	**78,381**	**118,547**	**230,754**	**248,149**	**181,927**	**208,232**	**157,943**	**366,175**	**235,344**
	19%	Labor					47,436	38,053	40,392	30,637	71,029	45,651
	23%	Capitalized Engineering/Supv					54,513	44,266	47,540	36,059	83,599	53,730
	4%	Material					9,208	8,319	8,623	6,540	15,163	9,745
	24%	Contractor					65,173	38,437	50,839	38,561	89,400	57,458
	12%	Non-Labor Overheads					28,274	20,859	24,059	18,248	42,307	27,191
	18%	Non-Labor Other					43,546	31,993	36,780	27,898	64,678	41,569
		Contingency							-	-	-	-
2		Material Condition Non Modeled	**38,625**	**29,057**	**36,892**	**50,126**	**40,995**	**38,516**	**29,899**	**23,306**	**53,206**	**34,695**
	15%	Labor					6,170	6,552	4,576	3,567	8,144	5,310
	23%	Capitalized Engineering/Supv					8,693	9,517	6,797	5,298	12,095	7,887
	8%	Material					3,389	2,677	2,280	1,777	4,057	2,646
	32%	Contractor					14,039	10,070	9,509	7,412	16,921	11,034
	4%	Non-Labor Overheads					1,540	1,938	1,312	1,022	2,334	1,522
	18%	Non-Labor Other					7,165	7,761	5,425	4,229	9,654	6,295
		Contingency							-	-	-	-
3		Material Condition Renewals	**12,248**	**24,942**	**36,093**	**30,637**	**23,331**	**31,816**	**29,784**	**18,363**	**48,147**	**30,446**
	35%	Labor					7,887	11,783	10,561	6,511	17,072	10,796
	22%	Capitalized Engineering/Supv					4,885	6,971	6,474	3,991	10,465	6,618
	3%	Material					582	1,324	771	475	1,246	788
	8%	Contractor					2,186	2,347	2,514	1,550	4,064	2,570
	10%	Non-Labor Overheads					2,657	2,462	3,088	1,904	4,992	3,157
	21%	Non-Labor Other					5,134	6,929	6,377	3,932	10,309	6,519
		Contingency							-	-	-	-
4		Vintage Service Replacements	**56,635**	**40,443**	**42,818**	**32,955**	**17,165**	**11,354**	**12,381**	**14,363**	**26,744**	**28,496**
	11%	Labor					1,016	2,989	1,354	1,571	2,926	3,117
	24%	Capitalized Engineering/Supv					4,074	2,744	2,951	3,424	6,375	6,793
	1%	Material					230	135	164	190	353	377
	39%	Contractor					8,127	739	4,865	5,644	10,509	11,197
	4%	Non-Labor Overheads					442	929	536	621	1,157	1,233
	20%	Non-Labor Other					3,277	3,820	2,511	2,913	5,424	5,779
		Contingency							-	-	-	-
5		Commercial and Industrial Meters	**program was included in Material Condition Non Modeled prior to**				**1,363**	**2,684**	**3,000**	**503**	**3,503**	**1,966**
	9%	Labor					94.91	344	269	45	314	176
	23%	Capitalized Engineering/Supv					254.52	677	690	116	805	452
	9%	Material					186.06	367	260	44	304	170
	42%	Contractor					644.56	771	1,264	212	1,476	828
	1%	Non-Labor Overheads					7.41	49	33	5	38	21
	16%	Non-Labor Other					175.05	476	484	81	565	317
		Contingency							-	-	-	-
6		**Total Capital**	**194,296**	**172,823**	**234,350**	**344,473**	**331,003**	**266,297**	**283,297**	**214,479**	**497,775**	**330,947**

Question:

118. Refer to pages 25-30 of Mr. Griffin's direct testimony on the MAOP transmission pipeline compliance program. Please:
a. Identify what deficiencies or shortcomings exist with traceable and verifiable records for each of the pipeline segments targeted for 2023 through 2025.
b. For the pipelines in subpart (a) to this interrogatory, identify and explain what specific steps the Company has taken to recreate those missing records by means other than pipeline replacement, as provided in 49 CFR 192.624.
c. For each of the targeted pipelines in 2023 to 2025, describe what smart pigging, In Line Inspection (ILI), and other analysis of the pipeline was performed in the past 5 years to establish the integrity of the pipeline and the level of pipe degradation.
d. For each of the targeted pipelines in 2023 to 2025, provide the pressure level that the pipeline had previously been operating at, the current pressure, and the level to which it could be reduced.
e. Provide a copy of the analysis showing the evaluation performed by the Company to re-establish the MAOP by hydrotesting various segments of the targeted pipelines or by other means before reaching the conclusion to replace the pipelines.
f. Identify any MAOP projects in the past 5 years or planned for 2024 and 2025 where the Company was able to re-establish the MAOP and material properties without replacing the pipeline segment. Provide the name of the project, the length, year of the pipeline, the deficiencies in the records, and describe how the Company was able to recreate the records and re-establish the MAOP without pipe replacement.

Response:

For subsections a-e, see attachment U-21490-AG-CE-0276-Griffin_ATT_1.

For subsection f, see attachment U-21490-AG-CE-0276-Griffin_ATT_2.

Witness: MICHAEL P. GRIFFIN
Date: April 4, 2024

U-21490-AG-CE-0276-Griffin_ATT_1									
Project ID	Project Description	Project Summary & Reason	Location	2022 Actual	2023 Projection	2024 Projection	2025 Projection	a	b
GL-03042	SAG-LN 1900-REM MAOP	On the Line 1900 piping at Grand Blanc, the pressure test was conducted too low to meet class 3 requirements on the Launcher/Receiver and associated piping.	Flint, MI	71,120	1,662			The segments of pipe for GL-02388 were identified by the Standard Engineering Analysis to have a pressure test that is non-commensurate with the MAOP of the System that it is coupled.	Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis. MAOP will be re-established with pressure testing.
GL-03181	NVL-1400 Pontiac Trail VS Pipe Repl	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located at Pontiac Trail Valve Site on Line 1400 and the crossover piping that connects to Line 2020.	Milford, MI	744	758,251			The segments of pipe for GL-03181 were identified by the Standard Engineering Analysis to have a pressure test that is non-commensurate with the MAOP of the System that it is coupled.	Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis. MAOP was re-established with pressure testing.
GL-03197	SAG-LN 100A Mt Pleasant Vs MAOP X Gap	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located on the crossover piping that connects Line 100A to Line 100B at Mt. Pleasant Valve Site.	Mt Pleasant, MI	3,647	1,728,088	40,555		The segments of pipe for GL-03197 were identified by the Standard Engineering Analysis to have a pressure test that is non-commensurate with the MAOP of the System that it is coupled.	Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis. MAOP will be re-established with replacement.
GL-03210	SAG-100A Mt. Pleasant VS-16in Vlvs	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located on the crossover valves at Mt. Pleasant Valve Site. This work aligns with Pipeline Integrity direct assessment planned for 2023. Not completing this gap closure with the Integrity work will result in duplicate work to draw down the line again in a later year.	Mt Pleasant, MI	-	1,147,748	40,555		The segments of pipe for GL-03210 were identified by the Standard Engineering Analysis to have a pressure test that is non-commensurate with the MAOP of the System that it is coupled.	Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis. MAOP will be re-established with replacement.
GL-03261	NVL Ln 1400 Milford Rd Pipe Repl	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located under Milford Road on Line 1400.	Milford, MI	281	1,721,477			The segments of Pipe for GL-03261 were identified during the Standard Engineering Analysis to be non-commensurate with the MAOP for the System that they are coupled.	Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis. MAOP will be re-established with replacement.
(13679)	STC-LN 1060 MT. CLEMENS LR DRAIN RETIREMENT	On Line 1060 at Mt Clemens City Gate, the Launcher/Receiver piping has pressure test documentation that does not meet the TVC (Traceable, Verifiable, Complete) requirements per 192.624.	Mt Clemens, MI			475,130		The segments of pipe for Project ID 13679 were identified by the Standard Engineering Analysis to have a pressure test that is not Traceable, Verifiable, and Complete.	New pressure test records will not be required when pipe is retired, and company does not intend to use other means to re-create them.
(1963)	SAG-100A Blanchard Rd VS Tap Vlv Repl	On Line 48, the tap valve and pup assembly are missing pressure test documentation to meet the TVC (Traceable, Verifiable, Complete) requirements per 192.624.	Shepherd, MI				588,491	The segments of pipe for Project ID 1963 were identified by the Standard Engineering Analysis to have a pressure test that is not Traceable, Verifiable, and Complete.	New pressure test records will be created with replacement, and company does not intend to use other means to re-create them. See part e.
(9059)	Line 1900 - Metamora City Gate - Hot Tap Replacement & Mainline Valve Install	Replacement of transmission pipeline segment with incomplete MAOP records that cannot be resolved through pressure testing. This MAOP Gap is located at Metamora City Gate. On Line 1900 at Metamora City Gate, the hot tap piping is missing pressure test documentation to meet the TVC (Traceable, Verifiable, Complete) requirements per 192.624.	Metamora, MI				2,636,190	The segments of pipe for Project ID 9059 were identified by the Standard Engineering Analysis to have a pressure test that is not Traceable, Verifiable, and Complete.	New pressure test records will be created with replacement, and company does not intend to use other means to re-create them. See part e.
(9060)	Line 2700 - Kern Road Valve Site MAOP gap	Replacement of transmission pipeline segment with incomplete MAOP records. This MAOP Gap is located at Kern Road Valve Site on Line 2700.	Oakland Charter Township, MI				557,559	The segments of pipe for Project ID 9060 were identified by the Standard Engineering Analysis to have a pressure test that is not Traceable, Verifiable, and Complete.	New pressure test records will be created with replacement, and company does not intend to use other means to re-create them. See part e.
	TOTAL EXPENDITURE			**75,792**	**5,357,225**	**556,240**	**#######**		

U-21490-AG-CE-0276-Griffin_ATT_1				
Project ID	Project Description	c	d	e
GL-03042	SAG-LN 1900-REM MAOP	L1900-4 was last pigged in 2021. No digs occurred and no corrosion was found beyond expected tolerances.	Line was running at 960 MAOP. Current pressure is 957 MAOP. Segment's MAOP will be restored to 960 MAOP when project is completed. No pressure protection is available nearby to allow for pressure reduction to be feasible.	Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis. The company plans on performing a pressure test to remediate the issue.
GL-03181	NVL-1400 Pontiac Trail VS Pipe Repl	L1400-1 was last pigged in 2019. 5 digs occurred, with 4 replacements.	Line was running at 800 MAOP. Current pressure is 800 MAOP. Condition has been remediated via pressure testing. No pressure protection is available nearby to allow for pressure reduction to be feasible.	Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis. The company performed a pressure test to remediate the issue.
GL-03197	SAG-LN 100A Mt Pleasant Vs MAOP X Gap	Segments were assessed by Direct Assessment (DA) in 2023, as it is unpiggable. Seam threat on 1950's pipe could not be addressed by DA, so it was replaced. DA did one other dig and one replacement outside of the scope of this project.	Line was running at 800 MAOP. Current pressure is 800 MAOP. Condition has been remediated via replacement. No pressure protection is available nearby to allow for pressure reduction to be feasible.	Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis. Replacement eliminated seam threat on 1950's pipe. Replacement was less disruptive to system operation and simpler project execution than hydrotesting.
GL-03210	SAG-100A Mt. Pleasant VS-16in Vlvs	Segments were assessed by DA in 2023, as it is unpiggable. Seam threat on 1950's pipe could not be addressed by DA, so it was replaced. DA did one other dig and one replacement outside of the scope of this project.	Line was running at 800 MAOP. Current pressure is 800 MAOP. Condition has been remediated via replacement. No pressure protection is available nearby to allow for pressure reduction to be feasible.	Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis. Replacement eliminated seam threat on 1950's pipe. Replacement was less disruptive to system operation and simpler project execution than hydrotesting.
GL-03261	NVL Ln 1400 Milford Rd Pipe Repl	L1400-1 was last pigged in 2019. 5 digs occurred, with 4 replacements.	Line was running at 800 MAOP. Current Pressure is 800 MAOP. Condition has been remediated via replacement. No pressure protection is available nearby to allow for pressure reduction to be feasible.	Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis. Replacement was chosen as existing pipe was not designed for current class.
(13679)	STC-LN 1060 MT. CLEMENS LR DRAIN RETIREMENT	Piping has not been assesed in the last 5 years.	Line was running at 800 MAOP. Current Pressure is 800 MAOP. Pressure restrictions for this line are too low to meet customer deliverability requirements.	Company has investigated the other options available in 192.624 and has chosen retirement as the most practicable option to comply. Piping is not utilitzed anymore by operations in lieu of a more efficient way of liquids disposal.
(1963)	SAG-100A Blanchard Rd VS Tap Vlv Repl	Piping has not been assesed in the last 5 years.	Lines run at 800 MAOP. Current Pressure is 800 MAOP. No pressure protection is available nearby to allow for pressure reduction to be feasible.	Company has investigated the other options available in 192.624 and has chosen replacement as the most practicable option to comply due to this option being less disruptive to system operation and simpler project execution than hydrotesting.
(9059)	Line 1900 - Metamora City Gate - Hot Tap Replacement & Mainline Valve Install	Piping has not been assesed in the last 5 years.	Lines run at 960 MAOP. Current Pressure is 960 MAOP. No pressure protection is available nearby to allow for pressure reduction to be feasible.	Company has investigated the other options available in 192.624 and has chosen replacement as the most practicable option to comply. Segments will be remediated in conjuction with a mainline valve installation which will allow for outage flexibility and allow compliance with valve spacing requirements.
(9060)	Line 2700 - Kern Road Valve Site MAOP gap	Segments were inspected by transmission DA in 2021. No corrosion was found beyond expected tolerances.	Lines run at 960 MAOP. Current Pressure is 960 MAOP. No pressure protection is available nearby to allow for pressure reduction to be feasible.	Company has investigated the other options available in 192.624 and has chosen replacement as the most practicable option to comply due to this option being less disruptive to system operation and simpler project execution.
	TOTAL EXPENDITURE			

U-21490-AG-CE-0276-Griffin_ATT_2

Project Name	Project Year	Length (miles)	Segment In-service Date	Deficiencies in records	Describe how we were able to use testing to restablish without replacement.
GL-02392 L1600 Hydrotest	2021	10.442	1956	Standard Engineering Analysis determined pressure Test documentation could not be used to establish MAOP via 192.619 (a)(2).	Segment was re-tested to obtain new pressure test records. Standard engineering analysis determined that material records were TVC for this pipe population.
GL-03430 STC L1060 Hydrotest GL-03432 MT Clemens L1060 Hydrotest	2024 (tentative)	0.066	2004	Standard Engineering Analysis determined pressure test is not Traceable, Verifiable, and Complete.	Segments will be re-tested to obtain new pressure test records. Material Verification will be performed to obtain TVC material records for this pipe population.
Note: These two are the two pressure tests that are 192.624 eligible.					

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Question:

127. Refer to WP-MPG-2 on MAOP pipeline projects. For project 9059, please:
a. Provide the cost of the project by year from inception to completion.
b. Provide the phases of project development for each project with timeline and related cost and the phase that the project is currently in.

Response:

a. The amounts shown on my workpaper, WP-MPG-2, are the total projected amounts by year from inception to completion.

b. For projects of this nature, survey, engineering, and design begins the year ahead of construction. Construction is typically the second year of the project, and the year in which the greatest amount of spending occurs. This project has not kicked off yet, but engineering, design, and survey are projected to begin in the fall of 2024. The Company projects to complete construction, restoration, and closeout all in 2025.

Witness: MICHAEL P. GRIFFIN
Date: April 2, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program Capital
2022 Through 2025 MAOP Pipeline Projects

Case No. U-21490
WP-MPG-2
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MAOP Pipeline Projects

Project ID	Project Description	Project Summary & Reason	Location	2022 Actual	2023 Projection	2024 Projection	2025 Projection	9 Months Ending 9/30/2024 Projection	12 Months Ending 9/30/2025 Projection
GL-02042	KZO-1300 STA730+07-732+54 Pipe	Final reconciliation costs of prior years project.	Kalamazoo, Mi	11,371	(38,877)			-	-
GL-02046	STC-Lahser Lateral Pipe Repl	Final reconciliation costs of prior year project.	Southfield, MI	-	(5,783)			-	-
GL-02048	SAG-300 Mdlnd Rd at Kchvle Pipe Repl	Order cancelled and moved to O&M Original Scope: Replace 1,103 ft of 12" pipeline on Midland Rd. (STA 843+48 to 854+51). Scope changed to the replacement of 6 elbows within 1,103' segment (no MAOP gap on pipe). Must be funded as O&M.	Midland, MI	-	(36,231)			-	-
GL-02112	FDM-3070 2.4 Miles Pipe Repl (Blissfield	Reconciliation of prior years project	Blissfield, MI	(1,275)				-	-
GL-02388	SAG-300 Sta882+44,902+25 Pipe Repl	Project completed in 2018. At final closeout costs moved to this order from GL--02079 in the Del. Base PL program.	Midland/Zilwaukee	532,012				-	-
GL-02397	FDM-400 Fenton Int MAOP Pipe Repl *CNCL*	In 2018, MAOP gap closed per Regulatory & Compliance records reconciliation. GL-02397 project scope cancelled.	Fenton, MI	(192,419)				-	-
GL-03042	SAG-LN 1900-REM MAOP	On the Line 1900 piping at Grand Blanc, the pressure test was conducted too low to meet class 3 requirements on the Launcher/Receiver and associated piping.	Flint, MI	71,120	1,662			-	-
GL-03181	NVL-1400 Pontiac Trail VS Pipe Repl	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located at Pontiac Trail Valve Site on Line 1400 and the crossover piping that connects to Line 2020.	Milford, MI	744	758,251			-	-
GL-03197	SAG-LN 100A Mt Pleasant Vs MAOP X Gap	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located on the crossover piping that connects Line 100A to Line 100B at Mt. Pleasant Valve Site.	Mt Pleasant, MI	3,647	1,728,088	40,555		34,862	5,693
GL-03210	SAG-100A Mt. Pleasant VS-16in Vlvs	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located on the crossover valves at Mt. Pleasant Valve Site. This work aligns with Pipeline Integrity direct assessment planned for 2023. Not completing this gap closure with the Integrity work will result in duplicate work to draw down the line again in a later year.	Mt Pleasant, MI	-	1,147,748	40,555		34,862	5,693
GL-03261	NVL Ln 1400 Milford Rd Pipe Repl	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located under Milford Road on Line 1400.	Milford, MI	281	1,721,477			-	-
GL-95614	Gas MAOP Standardization Eng Anal (MSEA	Settlement costs		(1,386)				-	-
GM-00494	FDM-Tecumseh Odorizor	Reconciliation of prior years project	Tecumseh, MI	188,264				-	-
(13679)	STC-LN 1060 MT. CLEMENS LR DRAIN RETIREMENT	On Line 1060 at Mt Clemens City Gate, the Launcher/Receiver piping has pressure test documentation that does not meet the TVC (Traceable, Verifiable, Complete) requirements per 192.624.	Mt Clemens, MI			475,130		408,438	66,692
(1963)	SAG-100A Blanchard Rd VS Tap Vlv Repl	On Line 48, the tap valve and pup assembly are missing pressure test documentation to meet the TVC (Traceable, Verifiable, Complete) requirements per 192.624.	Shepherd, MI				588,491	-	505,887
(9059)	Line 1900 - Metamora City Gate - Hot Tap Replacement & Mainline Valve Install	Replacement of transmission pipeline segment with incomplete MAOP records that cannot be resolved through pressure testing. This MAOP Gap is located at Metamora City Gate. On Line 1900 at Metamora City Gate, the hot tap piping is missing pressure test documentation to meet the TVC (Traceable, Verifiable, Complete) requirements per 192.624.	Metamora, MI				2,636,190	-	2,266,158
(9060)	Line 2700 - Kern Road Valve Site MAOP gap	Replacement of transmission pipeline segment with incomplete MAOP records. This MAOP Gap is located at Kern Road Valve Site on Line 2700.	Oakland Charter Township, MI				557,559	-	479,297
(1964)	2026 Emergent Capital MAOP Replacement Project	Replacement of transmission pipeline segment with incomplete MAOP records that cannot be resolved through pressure testing. Segment location TBD.					200,000	-	171,927
	TOTAL EXPENDITURE			**612,358**	**5,276,334**	**556,240**	**3,982,240**	**478,163**	**3,501,346**

Question:

128. Refer to WP-MPG-3 Field Measurement projects. For each of the following projects (GM-00543, GM-00995, GM-01024, 13731, 13750, 13753, and 13773), please provide the following information:
a. The cost of the project by year from inception to completion.
b. Explain what is the problem and why the project is necessary?
c. What alternatives were evaluated and what financial benefits will result from completion of the project.
d. The phases of project development for each project with timeline and related cost and the phase that the project is currently in.

Response:

a. See attachment U21490-AG-CE-0286-Griffin_ATT_1 which shows the project costs from inception to completion.
b. See attachment U21490-AG-CE-0286-Griffin_ATT_1
c. See attachment U21490-AG-CE-0286-Griffin_ATT_1
d. See attachment U21490-AG-CE-0286-Griffin_ATT_1

Witness: MICHAEL P. GRIFFIN
Date: April 3, 2024

U-21490-AG-CE-0386-Griffin_ATT_1

Consumers Energy Company

Actual and Projected Capital Expenditures for the Capacity/Deliverability Program

Deliverability Base Field Measurement Projects

Project ID	Project	Location	Project Reason	Further Information/Necessity	Alternatives Evaluated/Financial Benefits
GM-00543	FDM-Laingsburg Int Meter Repl	Laingsburg Int	Improve measurement accura	Improve measurement accuracy. Ultrasonic measurement installations allow for less measurement uncertainty in the system.	This is a new Interstage meter installation. Losses in the system are evaluated at a system wide level and a sectionalized level. The reported losses are based on the overall system. If there are losses in the system, sectionalized areas are evaluated to try to solve losses in the system as they occur. A new meter installation at this valve site will allow us to diagnose and troubleshoot losses on LN 400 should there ever be losses incurred on this line
GM-00995	SAG-Grand Blanc Mtr Run Repl	Grand Blanc Junction (Ln 500 to Ln 1900 metering)	Meters that are inoperable. Improve Measurement accuracy	Asset life is past its reasonable lifespan. Concrete supports are crumbling and orifice meter is not serviceable anymore. In order to get reliable measurement again and ensure the site remains in a safe condition going forward, this work will need to happen. As the work takes place, this will also provide value to LAUF.	Sectionalized LAUF by Interstage pipeline will allow us to diagnose and troubleshoot losses on LN 500 should there ever be losses incurred on this line. Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, you can either retire or upgrade. This is a Interstage meter.
GM-01024	KZO-1200A White Pigeon ROM	White Pigeon Compressor Station	Improve measurement accuracy	Improve measurement accuracy. Ultrasonic measurement installations allow for less measurement uncertainty in the system. This will provide LAUF information on LN 1200A.	This is a new Interstage meter installation. Losses in the system are evaluated at a system wide level and a sectionalized level. The reported losses are based on the overall system. If there are losses in the system, sectionalized areas are evaluated to try to solve losses in the system as they occur. A new meter installation at this valve site will allow us to diagnose and troubleshoot losses on LN 1200A should there ever be losses incurred on this line
13731	Williamston Transmission Meter Proving Station	Webberville	Validation and testing of transmission meters and analysis equipment. Lab for testing gas samples in the system	API-1164 requires new measurement equipment to be tested prior to install. This will provide a dedicated facility to test measurement equipment prior to going into production. There are means of testing distribution measurement assets but currently no means of testing for transmission measurement assets. The facility will also have lab grade gas analysis equipment which will save capital expenditure for sending samples to labs.	There is currently no facility for testing gas measurement equipment in a controlled setting. There is no known alternative to gain the same benefit.
13750	Lahser USM Installation	Lahser	Improve measurement accuracy	Currently an Orifice meter that is beyond its reasonable lifespan. One station that is at risk of operational problems in measurement due to the age of the asset. This should also help improve LAUF as there are less change outs in parts as Ultrasonic meters and Coriolis meters are used as replacements of Orifice meters in most cases.	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, you can either retire or upgrade. This is an LAUF meter.
13753	Perry Morrice Meter Replacement	Perry Morrice	Improve measurement accuracy	Currently an Orifice meter that is beyond its reasonable lifespan. One station that is at risk of operational problems in measurement due to the age of the asset. This should also help improve LAUF as there are less change outs in parts as Ultrasonic meters and Coriolis meters are used as replacements of Orifice meters in most cases.	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, you can either retire or upgrade. This is an LAUF meter.
13773	Rose Center Meter Replacement	Rose Center	Improve measurement accuracy	Currently an Orifice meter that is beyond its reasonable lifespan. One station that is at risk of operational problems in measurement due to the age of the asset. This should also help improve LAUF as there are less change outs in parts as Ultrasonic meters and Coriolis meters are used as replacements of Orifice meters in most cases.	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, you can either retire or upgrade. This is an LAUF meter.

Notes:

1) 20% of a project cost is spent in engineering, design, and material acquisition, 65% is spent in construction, and the balance is spent after in service (project closeout)

U-21490-AG-CE-0386-Griffin_ATT_1

Consumers Energy Company — Case No. U-21490

Actual and Projected Capital Expenditures for the Capacity/Deliverability Program — ~~WP-MPG-3~~

Deliverability Base Field Measurement Projects — Page 1 of 2

Project ID	Project	Project Timeline	Current Phase	2022 Actual	2023 Projection	2024 Projection	2025 Projection	2026 Projection	9 Months Ending 9/30/2024 Projection	12 Months Ending 9/30/2025 Projection
GM-00543	FDM-Laingsburg Int Meter Repl	See Note 1	Engineering design getting ready to kick-off	11,313	0		4,504,000			3,598,624
GM-00995	SAG-Grand Blanc Mtr Run Repl	See Note 1	Engineering design getting ready to kick-off	0	11,868		4,712,000			3,764,813
GM-01024	KZO-1200A White Pigeon ROM	See Note 1	Engineering Design kicked off	0	1,102	3,500,000			2,796,444	703,556
13731	Williamston Transmission Meter Proving Station	See Note 1	Design planned for 2025 with construction planned in 2026				680,000	9,200,000		543,309
13750	Lahser USM Installation	See Note 1	Design planned to kick off at the end of Q2				800,000			639,187
13753	Perry Morrice Meter Replacement	See Note 1	Design planned to kick off at the end of Q2				800,000			639,187
13773	Rose Center Meter Replacement	See Note 1	Design Planned to kick off in Q2/Q3 of 2025 with the project execution in 2026.				300,000	800,000		239,695
										10,128,371

Notes:

1) 20% of a project cost is spent in engineering, design, and material acquisition, 65% is spent in construction, and the balance is spent after in service (project closeout)

Consumers Energy Company
Actual and Projected Capital Expenditures for the Capacity/Deliverability Program
Deliverability Base Field Measurement Projects

Case No. U-21490
WP-MPG-3
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Project ID	Project	Location	Project Reason	2022 Actual	2023 Projection	2024 Projection	2025 Projection	9 Months Ending 9/30/2024 Projection	12 Months Ending 9/30/2025 Projection
GL-02402	MAR-Blue Lake 36 Site Upgrds	Blue Lake	Improve measurement accuracy	7,569	0				
GL-02403	MAR-Goose Creek Site Upgrds	Goose Creek	Improve measurement accuracy	120,666	1,418				
GM-00130	SAG-Dutch Rd CG GC Sampling Inst	Dutch RD	Improve Gas Quality Readings	-6,825	0				
GM-00200	STC-Orion CG GC Sampling Inst	Orion CG	Improve Gas Quality Readings	-6,825	0				
GM-00201	STC-Pont Adms Rd CG GC Sampling Inst	Adams Rd Mtr Sta (Pontiac)	Improve Gas Quality Readings	-6,825	0				
GM-00249	OVC-Plant H2S Analyzer Repl	Overisel Compression Stati	Improve measurement accuracy	182	0				
GM-00250	RAY-H2O Analyzer Replacement	Ray Underground Storage	Improve measurement accuracy	-21,824	0				
GM-00387	SAG-Coleman CG Meter Repl	Coleman-Beaverton CG	Improve measurement accuracy	0	1,048				
GM-00438	STC-Red Run CG Reg Rbld, Material(Measur	Red Run CG	Improve measurement accuracy	-31,808	0				
GM-00458	FDM-Line 100A Chelsea VS-MTR Repl	Chelsea 100A VS	Improve measurement accuracy	-3,267	0				
GM-00542	RAY-Run Cntrl Repl, RTU Inst	Ray Compressor	Failed Valve Replacement	-65,891	-17,071				
GM-00543	FDM-Laingsburg Int Meter Repl	Laingsburg Int	Improve measurement accuracy	11,313	0		4,504,000		3,598,624
GM-00544	WPC-WPCS Fuel Meter Automation	White Pigeon Compressor	Improve measurement accuracy	18,930	0				
GM-00547	SAG-Summerton Rd GC Upgrade *CNCL*	Summerton Rd	Cancelled order	0	-287				
GM-00553	JXN-GC, GQ Mobile Trailer	Jackson General	Mobile Gas Quality Trailer for use everywhere	7,095	0				
GM-00554	NVL-Gas Sampling System Upgd	Northville Compressor	Improve Gas Quality Readings	194,049	-0				
GM-00564	JXN-Strg Orifice Mtr O-120 - CNCL	Ira Storage	Reclassify old order to O&M/COR at closeout	-106,819	-1,490,292				
GM-00596	NVL-500 GrandBlancJnct Meter Repl	Grand Blanc In 500 to 2800	Improve measurement accuracy	-319	39,337				
GM-00597	NVL-ClarkstonInt USM Inst	Clarkston Jct Interchange	Improve measurement accuracy	0	15,561				
GM-00635	STC-LN 1700 Ray Mtr Run Pipe Repl *CNCL*	Ray Underground Storage	Cancelled order	-5,136	0				
GM-00636	STC-LN 1900 Ray Mtr Run Pipe Repl *CNCL*	Ray Underground Storage	Cancelled order	-218	0				
GM-00664	KZO-Plainwell VS GC Inst	Plainwell VS	Improve measurement accuracy	58,706	848				
GM-00666	RAY Comp: Transducer Repl *CNCL*	Ray Compression Plant 3	Cancelled order	-4,329	0				
GM-00668	MAR-FGU Meter Inst (2019)	Marion Winterfield Storage	Improve measurement accuracy	0	-24,290				
GM-00670	OVS-Dorr CG Mtr Repl	Dorr CG	Improve measurement accuracy	136	978				
GM-00674	JXN-USM Remote Trailer 1	Jackson General	Improve measurement accuracy	83,008	0				
GM-00675	JXN- Park Road City Gate-EGM Decomm	Various	Improve measurement accuracy	0	0				
GM-00682	FDM-Spring Arbor CG H2O, H2S Inst	Spring Arbor	Improve measurement accuracy	592	0				
GM-00693	NVL-Lyon 29-34 Liquid Handling Ugrd	Lyon	Project Moved to Storage Prg	-411,132	370				
GM-00746	NVL-Walled Lake CG Fuel Mtr Repl 2015	Walled Lake CG	Improve measurement accuracy	0	0				
GM-00748	OVS-Salem GC, H2O, H2S Inst	Salem CG	Improve Gas Quality Readings	6,514	0				
GM-00754	JXN 34 -Dewitt Township	Dewitt 34 TMS	System Improvements	440,052	7,743				
GM-00767	KZO-Galesburg CG EGM Inst *CNCL*	Galesburg CG	Idle Order written off to O&M	-2,428	0				
GM-00768	KZO-Palmer CG EGM Inst *CNCL*	Palmer CG	Idle Order written off to O&M	-14,725	0				
GM-00769	KZO-M Ave CG EGM Inst *CNCL*	M Ave CG	Idle Order written off to O&M	-1,321	0				
GM-00770	KZO-Nazareth Rd CG EGM Inst *CNCL*	Nazareth CG	Idle Order written off to O&M	-2,760	0				
GM-00771	KZO-MGU Gun Plain CG EGM Inst *CNCL*	Gun Plain CG	Idle Order written off to O&M	-1,188	0				

Consumers Energy Company — Case No. U-21490
Actual and Projected Capital Expenditures for the Capacity/Deliverability Program — WP-MPG-3
Deliverability Base Field Measurement Projects — Page 2 of 2

Project ID	Project	Location	Project Reason	2022 Actual	2023 Projection	2024 Projection	2025 Projection	9 Months Ending 9/30/2024 Projection	12 Months Ending 9/30/2025 Projection
GM-00773	MAR - CG H2O & H2S Install	Marion CG	Improve Gas Quality Readings	0	-119,717				
GM-00774	MAR - McBain CG H2O & H2S Inst	McBain CG	Improve Gas Quality Readings	1,106	-23,079				
GM-00852	FDM-Vector Ray Msrmnt	Ray Compressor	Improve measurement accuracy	572,260	202,787				
GM-00853	FDM-Vector Hartland Msrmnt	Hartland	Improve measurement accuracy	236,582	757,745				
GM-00878	MAR-Falmouth CG Meter Repl	Falmouth CG	Improve measurement accuracy	598,294	6,056				
GM-00879	JXN-Grand Ledge GC Building Intallation	Grand Ledge CG	Improve Gas Quality Readings	4,829	0				
GM-00913	KZO-Kip RNG-TMS Site *CNCL*	Kipp RNG	Customer Funded, Payment processed in 2021	17,585	0				
GM-00922	SAG Summerton Rd. Meter Calibration	Summerton RD	Improve Gas Quality Readings	1,538	0				
GM-00923	SAG Summerton Rd. Meter Site Rb	Summerton RD	Failed Valve Replacement	927,788	3,811,083				
GM-00950	FDM-Chelsea Ln 100A Metering	Chelsea 100A	Improve measurement accuracy	135,338	2,067,636	100,000		79,898	20,102
GM-00964	GRN-Novilla RNG MS Inst	Keene TWP	TMS Site	213,998	-208,711				
GM-00969	JXN-Mosherville CG Meter Run Repl	Mosherville	Improve measurement accuracy	64,471	370,614				
GM-00987	BAY MEASUREMENT TRAINING FACILITY	Bay City Consumers Facility	Training lab for field workers	0	259,953				
GM-00995	SAG-Grand Blanc Mtr Run Repl	Grand Blanc Junction (Ln 500 to Ln 1900 metering)	Improve Measurement accuracy	0	11,868		4,712,000		3,764,813
GM-01024	KZO-1200A White Pigeon ROM	White Pigeon Compressor S	Improve measurement accuracy	0	1,102	3,500,000		2,796,444	703,556
GM-01025	White Pigeon Generator Fuel Meter Installation		KZO-1200A White Pigeon ROM+CA65:D66		0	870,000		695,116	174,884
GM-95000	MAR-FGU Meter Inst (2020) *CNCL*	Marion Winterfield Storage I	Improve measurement accuracy	0	10,783				
GM-95001	Transducer Repl Program	Various	Improve measurement accuracy	288,475	165,725	302,900	302,900	242,012	302,900
GM-95009	JXN-Thermostat Repl -Akron CG *CNCL*	Various	Improve measurement accuracy	-239	0				
GM-95012	DTE Interconnect *CNCL*	Oakland County	Improve measurement accuracy	-88	0				
GM-95309/9520	2023 Measurement Capital Tools	Various	Capital tools to improve measur	186,384	269,842	252,900	252,900	202,063	252,900
11214	O2,H2O,H2S Analyzer / GC Interconnect / city gate Installation	Various	Improve measurement accuracy/emergent projects			800,000	-	639,187	160,813
13731	Williamston Transmission Meter Proving Station	Webberville	Validation and testing of transmission meters and analysis equipment. Lab for testing gas samples in the system				680,000		543,309
13750	Lahser USM Installation	Lahser	Improve measurement accuracy				800,000		639,187
13753	Perry Morrice Meter Replacement	Perry Morrice	Improve measurement accuracy				800,000		639,187
13773	Rose Center Meter Replacement	Rose Center	Improve measurement accuracy				300,000		239,695
				3,503,492	**6,119,050**	**5,825,800**	**12,351,800**	**4,654,721**	**11,039,969**

Question:

129. Refer to WP-MPG-4 Deliverability Base Pipeline program. For each of the following projects (GL-02384, GL-02385, GL-02662, GL-02684, GL-03289, GL- 03315, GL-03317, GL-03336, 13515, 13521, 13700, 12920), please provide the following information:
a. Provide the cost of the project by year from inception to completion.
b. Explain what is the problem and why the project is necessary?
c. What alternatives were evaluated and what financial benefits will result from completion of the project.
d. The phases of project development for each project with timeline and related cost and the phase that the project is currently in.
e. Explain why projects GL -02384 and GL-02385 have the same project reason.
f. Provide a copy of the valve spacing study identifying the listed project for corrective action.
g. For project 13700, explain how replacing the valve will improve gas deliverability.
h. Explain why some projects do not have a GL prefix.

Response:

a. The annual amounts shown on my workpaper, WP-MPG-4 Deliverability Base Pipeline Program, are the annual amounts projected from inception to completion for these projects.
b. Please refer to the table below.
c. Please refer to the table below for alternatives that were evaluated for the subject projects. The subject projects are not being completed for financial benefit. Most projects in the Deliverability Base – Pipeline program are driven by code compliance or to improve system resiliency, deliverability, or safety.
d. In general, spending begins the year ahead of construction and allows for survey, engineering, and design to be completed. Construction is typically the second year of spending for the project, and the year in which the greatest amount of spending occurs. A small amount of funding is projected the year following construction to facilitate remaining restoration and closeout items. See below for detail of the listed project's current phase.
e. Both GL-02384 and GL-02385 have the same project description because Pinckney city gate "(CG)" and Dexter CG are both critical CG facilities on Line 2200 that do not currently have a mainline valve or dual taps. When Line 2200 is removed from service in this area, there is no way to maintain feed to either CG. The installation of a mainline valve and dual taps at both Pinckney and Dexter with improve deliverability because it will give the Company the option to continue to feed each CG if an outage on Line 2200 is required to the north of south of each city gate. The Company is taking advantage of a planned integrity outage on Line 2200 in 2024 to install sectionalizing valves at both Pinckney and Dexter CG to reduce the impact of any future outages on Line 2200.
f. A copy of the valve spacing study is included in CONFIDENTIAL attachment U-21490-AG-CE-0287-Griffin_CONF_ATT_1. This attachment identifies spacing issues on Line 300, Line 1500 and Line 2200 to be remediated by projects GL-03289, GL-03315, GL-02384, (13515), and (13521).

g. Perry-Morrice CG is a critical facility that does not currently have a mainline valve or dual taps. When Line 400 is removed from service in this area, there is no way to maintain feed to Perry-Morrice CG. This CG cannot take an outage at any time in the year and would require temporary feed if an outage occurs on Line 400. The load in fall, winter and spring is too high to reasonably supply with temporary gas. The installation of a mainline valve and dual taps will improve deliverability because it will give the Company the option to continue to feed Perry-Morrice CG if either portion of Line 400 needs an outage to the west or the east.
h. Some projects do not have GL prefixes yet because a GL number is assigned once charging to the project has started.

Project ID	Project	b. Project Necessity	c. Alternatives	d. Project Phase
GL-02384	FDM-Pinckney CG Dual Tap Inst.	Please see response e. above.	Placing a mainline valve at other sites along Line 2200 was evaluated to improve deliverability on Line 2200, but placing a mainline at an existing city gate site was determined to be most cost effective.	This project is in the engineering and design phase, with construction planned for 2024.
GL-02385	FDM - Line 2200 Dexter CG Mainline Valve & Dual Tap Install	Please see response e. above.	Placing a mainline valve at other sites along Line 2200 was evaluated to improve deliverability on Line 2200, but placing a mainline at an existing city gate site was determined to be most cost effective.	This project is in the engineering and design phase, with construction planned for 2024.
GL-02662	Line 500 - Torrey Road VS - Valve 504-26 & Dual Tap Valve Replacement	Valve 504-26 has issues sealing, this project is necessary to restore the ability to utilize the mainline valve in case of an emergency. It will also improve system deliverability at Flint CG Torrey Rd.	Repairs were attempted on these valves. A replacement project was created once it was determined the repairs were unsuccessful.	Work has not begun for this project. Construction is planned for 2025 with engineering and design kicking off in 2024.
GL-02684	There is no project by this number.	N/A	N/A	N/A
GL-03289	STC- 1500 Valve Spacing VS Inst	Because of a class change, valve spacing on Line 1500 was determined to be inadequate. This project is required to be compliant with code §192.179.	The only other alternative to remediate valve spacing issues would be pipeline relocation, installing a valve was determined to be the most cost effective option.	This project is in the engineering and design phase, with construction planned for 2024.
GL-03315	Line 2200 - Howell to Vector Hartland VS (Valve Site Installation due to valve spacing)	Because of a class change, valve spacing on Line 2200 was determined to be inadequate. This project is required to be compliant with code §192.179.	The only other alternative to remediate valve spacing issues would be pipeline relocation, installing a valve was determined to be the most cost effective option.	This project is in the engineering and design phase, with construction planned for 2024.
GL-03317	Line 1900 - Leonard-Lakeville CG - Valve 1936 & dual tap (1935 & 1937) replacements	This project is necessary to removing aging and unreliable assets on our system and improve	No alternative available for improving deliverability at this site.	Work has not begun for this project. Construction is planned for 2025 with

		system deliverability at Leonard-Lakeville CG.		engineering and design kicking off in 2024.
GL-03336	SAG Line 100A Lake George Class Location Change Pipe Repl	Because of a class change, the design pressure of this segment was determined to be inadequate for the current MAOP. This project is required to be compliant with code §192.611.	A pressure reduction was evaluated for Line 100A. System equipment and deliverability requirements could not support a pressure reduction on this pipeline. A pressure test was not feasible because the issue was driven by the pipe attributes.	This project is in the engineering and design phase, with construction planned for 2024.
(13515)	Line 300 - Arthur Rd Vs to Wise Rd VS INST (Valve Site Installation due to valve spacing)	Because of a class change, valve spacing on Line 300 was determined to be inadequate. This project is required to be compliant with code §192.179.	The only other alternative to remediate valve spacing issues would be pipeline relocation, installing a valve was determined to be the most cost effective option.	Work has not begun for this project. Construction is planned for 2025 with engineering and design kicking off in 2024.
(13521)	Line 300 - Gordonville to Zilwaukee VS INST (Valve Site Installation due to valve spacing)	Because of a class change, valve spacing on Line 300 was determined to be inadequate. This project is required to be compliant with code §192.179.	The only other alternative to remediate valve spacing issues would be pipeline relocation, installing a valve was determined to be the most cost effective option.	This project is in the engineering and design phase, with construction planned for 2024.
(13700)	FDM 400 Perry-Morrice Dual Tap Vlv. Inst.	Please see response g. above.	Placing a mainline valve at other sites along Line 400 was evaluated to improve deliverability on Line 400, but placing a mainline at an existing city gate site was determined to be most cost effective.	Work has not begun for this project. Construction is planned for 2025 with engineering and design kicking off in 2024.
(12920)	FDM 400 Laingsburg Int Vlv 401-24 Repl	Valve 401-24 has issues sealing, this project is necessary to improve the nearby Pressure Limiting Device's ability to control pressure for the MAOP differentials at Laingsburg.	Repairs were attempted on this valve. A replacement project was created once it was determined the repairs were unsuccessful.	Work has not begun for this project. Construction is planned for 2025 with engineering and design kicking off in 2024.

Witness: MICHAEL P. GRIFFIN
Date: April 3, 2024

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GL-00617	STC-Macomb VS 26in Pipe Repl	Macomb	Project from prior years final reconciliation	(69,001)	0			-	-
GL-01009	FDM-Fen Int Vlv-MtrRepl, Dead Leg Rmvl	Fenton	Project from prior years final reconciliation	4,094	0			-	-
GL-01301	SAG-100A Alma G to StL VS Pipe Repl	Alma	Project from prior years final reconciliation	67,456	0			-	-
GL-01314	STC-2070 Pipe Repl	Birmingham	Project from prior years final reconciliation	342	0			-	-
GL-02027	FDM-400 Fenton Int Vlv 404-24 Repl	Fenton	Project from prior years final reconciliation	(15,670)	0			-	-
GL-02029	KZO-1100 Freeport CG Dual Tap Vlv Inst	Freeport	Project from prior years final reconciliation	(13,200)	0			-	-
GL-02035	SAG-Lk Grge VS Vlv 106X20NS Repl	Lake George	Project from prior years final reconciliation	(11,367)	0			-	-
GL-02077	OVS-1100 Barber Rd VS BDV Repl	Freeport	Project from prior years (2019) final reconciliation	-	7			-	-
GL-02079	SAG-300 12" Repl- E. Garfield to Zill	Saginaw	Project from prior years final reconciliation costs moved to GL-02388 in the MAOP PL Program	(519,750)	0			-	-
GL-02090	STC-LN2070 Hamlin Rd VS Rebuild	Rochester Hills	Project from prior years final reconciliation	25,597	0			-	-
GL-02091	SAG-100A/500 Ovid VS LR Drain Vlv Repl	Ovid	Project from prior years (2019) final reconciliation	486	0			-	-
GL-02092	KZO-1300 Olmstead VS Vlv 1326 Repl	Kalamazoo	Project from prior years (2020) final reconciliation	88,652	19,772			-	-
GL-02093	SAG-500 Mainline Vlv 502-26 Repl	Owosso	Project from prior years (2020) final reconciliation	-	9,686			-	-
GL-02096	SAG-500 Vlv 503-26 Actuator Repl	Swartz Creek	Project from prior years (2020) final reconciliation	13	12,190			-	-
GL-02097	FDM-1100 Woodbury CG Vlv 1128 Repl	Lansing	Project from prior years final (2022) reconciliation	610	-31,809			-	-
GL-02098	FDM-100A Dansville VS LR Drain Vlv Repl	Iosco Township	Project from prior years final (2019) reconciliation	-	434			-	-
GL-02102	STC-1700 VectorCECO Int Dual Tap Inst	Ray	Project from prior years final (2021) reconciliation	225,282	16,499			-	-
GL-02319	SAG-50 MCV Dow Int Chk Vlv Inst	Midland	Project from prior years final (2019) reconciliation	-	-28,303			-	-
GL-02384	FDM-Pinckney CG Dual Tap Inst.	Pinckney	Line 2200 is a critical pathway for transporting gas into storage at Ray & St. Clair during the summer. The current configuration of Line 2200 cannot accommodate overlapping outage windows that can support both survey at Ray Compressor Station and Pinckney City Gate being out of service. Install new mainline valve and dual taps to increase the ability to take outages on 2200.	-	250,905	3,013,042		2,174,824	838,218
GL-02385	FDM - Line 2200 Dexter CG Mainline Valve & Dual Tap Install	Dexter	Line 2200 is a critical pathway for transporting gas into storage at Ray & St. Clair during the summer. The current configuration of Line 2200 cannot accommodate overlapping outage windows that can support both survey at Ray Compressor Station and Dexter City Gate being out of service. Install new mainline valve and dual taps to increase the ability to take outages on 2200.		246,364	3,079,940		2,223,111	856,829
GL-02410	MAR-2400A Merrit CG Tap Vlv Inst	Merritt	Project from prior years (2019) final reconciliation	2,130	0			-	-
GL-02412	STC-1060 25 Mile Rd Vlv Site	New Baltimore	Project from prior years (2020) final reconciliation	-	41,320			-	-
GL-02473	NVL-W Wayne CG Vlv 1621,1623 Repl	Farmington Hills	Project from prior years (2019) final reconciliation	-	8,713			-	-
GL-02580	NVL-Line 1020 Valve 4018 Repl	South Lyon	Project from prior years (2019) final reconciliation Carryover	966	0			-	-
GL-02621	NVL-Line 1020 Vlv 518 Repl	Northville	Project from prior years (2019) final reconciliation	-	50,685			-	-
GL-02622	NVL-Line 1020 Vlv 4028 Repl	South Lyon	Project from prior years (2019) final reconciliation	-	-7,402			-	-
GL-02641	MAR-Cadillac Rd 2424A Vlv Repl	Falmouth	Project from prior years (2020) final reconciliation	307	11,370			-	-
GL-02655	SAG-2100 LR Drain Repl Carpenter VS	Flint	Project from prior years (2019) final reconciliation	(181)	0			-	-

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GL-02656	STC-Cooldge CG Vlv 1632 Repl	Royal Oak	Project from prior years (2019) final reconciliation	-	23,381			-	-
GL-02657	STC-Cooldge CG 2070 DL Ret & 1600 LR Wrk	Royal Oak	Project from prior years (2020) final reconciliation	2,894	112,542			-	-
GL-02659	NVL-N Lyon CG Chck Vlv & BD Install	N Lyon	Project from prior years (2020) final reconciliation	-	16,053			-	-
GL-02662	Line 500 - Torrey Road VS - Valve 504-26 & Dual Tap Valve Replacement	Grand Blanc	Valve 504-26 has been identified as a difficult valve to isolate with. Recommended for replacement by operations.		0		2,344,657	-	1,692,381
GL-02664	Line 500 - Grand Blanc VS - Valve 506-26 and 8GSV2 Replacement	Grand Blanc	Valve 506-26 has been identified as a difficult valve to isolate with. Both valve 506-26 and 8GSV2 recommended for replacement by operations.		0		1,234,799	-	891,282
GL-02669	STC-1060 Mt Clem to STCS RCV Inst	New Baltimore	Project from prior years (2020) final reconciliation	(1,885)	23,490			-	-
GL-02671	STC-1600 Greenfld CG ML-Dual Tp Inst	Royal Oak	Project from prior years (2022) final reconciliation Addition of second 8" tap to Greenfield City Gate, as well as sectionalizing mainline 16" valve on Line 1600 in order to improve gas deliverability at Greenfield Valve Site.	1,470,999	-144			-	-
GL-02711	KZO-1200A Hackman Rd VS 1216A Repl	Sturgis	Project from prior years (2021) final reconciliation	48	22,975			-	-
GL-02751	SAG-500 Ovid VS Vlv 501x20N Repl	Ovid	20" crossover Valve 501X20N has been determined to be inoperable. Valve does not operate by hand or by operator. Long-term compliance with 49 CFR 192.745(b) requires replacement of the valve. Short-term and medium-term negative impacts to outage execution and pipeline emergency response on Line 100A, Line 500, and Ovid City Gate.	198,322	-49,557			-	-
GL-02768	SAG-300 Pipe Repl 79251-82475	Harrison	Class location change project on Line 300 that results in 3,224' of pipe needing to be replaced. Between GIS Station 79251 and 82475. (49 CFR 192.611). Project deferred.	70	0			-	-
GL-02771	OVS-1100 Pipe Repl 24108-24679	Grand Ledge	Class location change on Line 1100 that results in 571' of pipe needing to be replaced. Between GIS Station 24108 and 24679. (49 CFR 192.611)	480	3,187			-	-
GL-02772	OVS-1100 Pipe Repl 5713-5812	Freeport	Class location change on Line 1100 that results in 99' of pipe needing to be replaced. Between GIS Station 5715 and 5812. (49 CFR 192.611)	29,604	0			-	-
GL-02773	STC-McmbVS Vlv 1715E,1714,1528,1526W Rep	Macomb	Project from prior years (2021) final reconciliation	3,267	59			-	-
GL-02775	SAG-100A Pipe Repl 30454-30863	Rosebush	Project completed in 2022, asset in-service and restoration in 2023 Class location change on Line 100A that results in 408' of pipe needing to be replaced. Between GIS Station 30454 and 30863. (49 CFR 192.611)	1,200,204	-86,482			-	-
GL-02776	SAG-100A Pipe Repl 95442-95924	Perry	Project from prior years (2021) final reconciliation	32,423	10,559			-	-
GL-02777	SAG-100A Pipe Repl 9113-9750	Mt Pleasant	Project completed in 2022, asset in-service and restoration in 2023 Class location change on Line 100A that results in 637' of pipe needing to be replaced. Between GIS Station 9113 and 9750. (49 CFR 192.611)	4,546,136	-54,831			-	-
GL-02778	SAG-100C Pipe Repl 571095-571833	Mt Pleasant	Project completed in 2022, asset in-service and restoration in 2023 Class location change on Line 100C that results in 738' of pipe needing to be replaced. Between GIS Station 571095 and 571833. (49 CFR 192.611)	3,488,847	106,705			-	-
GL-02779	SAG-100C Pipe Repl 592488-592795	Clare	Class location change on Line 100C that results in 405' of pipe needing to be replaced. Between GIS Station 592488 and 592795. (49 CFR 192.611)	218	1,539,299			-	-
GL-02837	STC-1600 Evergreen VS Vlv #1628 Rpl	Royal Oak	Project from prior years (2021) final reconciliation	657,992	-285,308			-	-

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GL-02838	NVL-1200A Northville CS Vlv #1273 Rpl	Northville	Valve #1273 could not hold gas pressure greater than 30 psig in a closed position last year. This leakage problem caused many leak calls and created masking problems. Replace Valve 1273 to allow for the replacement of Valve #1610.	125,425	826			-	-
GL-02839	NVL-1600 Northville CS Vlv #1610 Rpl	Northville	Project from prior years (2021) final reconciliation	59,558	305,670			-	-
GL-02850	STC-Squirrel Rd VS 4" L/R Drain Vlv Repl	Lake Orion	Project from prior years (2021) final reconciliation	4,236	0			-	-
GL-02852	SAG-300 Woodcock Rd VS Vlv 309-12 Repl	Midland	Replace 12" mainline sectionalizing Valve 309-12 at Woodock Road Valve Site, Line 300. Valve 309-12 has significant sealing issues and has caused isolation problems during planned outages.	30,483	1,123,026			-	-
GL-02853	OVS-1300 Plainwell VS Vlv 6GSV3 Repl	Plainwell	Project from prior years (2020) final reconciliation	-	2,759			-	-
GL-02855	SAG-250 Mt Plsnt VS Vlv 251-16 Repl	Mt Pleasant	Project from prior years (2021) final reconciliation	20	0			-	-
GL-02857	SAG-300 Coleman-Beaverton CG Tap Repl	Coleman	Project from prior years (2020) final reconciliation	9,125	0			-	-
GL-02859	KZO-1200A V Drive VS Vlv 1242W Actu Repl	Homer	Project from prior years (2021) final reconciliation	2,884	0			-	-
GL-02937	FDM-1100 Dewitt St 1154&1154T20W Repl	Dewitt	Project from prior years (2021) final reconciliation	1,115	0			-	-
GL-03014	SAG-100A Valve Spacing VS INST	Mt Pleasant	Project completed in 2022, P2P Commissioning in 2023 Valve spacing study has indicated a new sectionalizing block valve is needed between Airport and Herrick VS on Line 100A. (49 CFR 192.179)	2,375,818	-78,045			-	-
GL-03022	FDM-1200A/B Blue Ridge VS Inst	Clarklake	Project from prior years (2022) final reconciliation	4,891,490	-45,363			-	-
GL-03024	FDM-1100 Lansing CG Arpt Rd Vlv Repl	Lansing	Project from prior years (2022) final reconciliation	1,530,368	-250			-	-
GL-03038	KZO-1200A Vlv 1207, 1208A Repl	White Pigeon	Valve 1207 is identified as inoperable. Long-term compliance with 49 CFR 192.745(b) requires replacement of the valve. Valve 1208A is an isolation valve needed in order to replace valve 1207, but it is known to leak by. 1208C has also been reported as inoperable.	226,931	2,842,868			-	-
GL-03046	KZO-1200B Vlv 1256B Repl	Jackson	Project from prior years (2022) final reconciliation	2,779,046	4,845			-	-
GL-03047	KZO-1200A,B MndnLeon 4in Tap Vlvs Repl	Bronson	Replacement of 1223A, 4" tap valves and associated piping from Lines 1200A and 1200B. In support of Mendon-Leonidas City Gate rebuild by M&R. To improve reliability and gas deliverability on Lines 1200A, 1200B, and Mendon-Leonidas City Gate. Valve 1223A does not seal and leaks by.	6,645	0			-	-
GL-03056	SAG 300 Zilwaukee Jct 314-12 BVD Repl	Saginaw	The blowdown valves at Zilwaukee have been recommeded for replacement by operations. The blowdown valves have been identified as leaking by.	54,551	178,843			-	-
GL-03071	MAR-2500 Bear Lk CG Vlv Inst	Kalkaska	Project from prior years (2022) final reconciliation	1,974,970	-25,685			-	-
GL-03113	SAG LN300 Midland CG Vlv 307-12N Repl	Midland	During the monthly valve alignment with operations, it has been indicated that Valve 307-12N cannot operate and needs replacement	58,893	522,847			-	-
GL-03114	NVL-LN1400 Highland CG Dual Tap Vlv Repl	Highland	Replacement of two 4" tap valves, two 4" check valves, and associated piping at Highland City Gate in support of CG rebuild and in order to improve gas deliverability.	210,505	947,586			-	-
GL-03115	FDM-400-1 Vlv Spacing VS Inst	Fenton	Valve spacing study has indicated a new sectionalizing block valve is needed between Lutz and Fenton VS on Line 400. (49 CFR 192.179)	1,727,824	-45,008			-	-
GL-03116	SAG-Atlas VS Vlv 1912 Repl	Grand Blanc	Project from prior years (2022) final reconciliation	1,031,638	64,107			-	-

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GL-03119	NVL 1400-1 Vlv Spacing VS INST	Milford	Valve spacing study has indicated a new sectionalizing block valve is needed between Highland and Pontiac Trail on Line 1400. (49 CFR 192.179)	16,291	1,213,876			-	-
GL-03126	SAG-100A-Pipe Repl 95177-95449	Farwell	Project completed in 2022, asset in-service in 2023 Class location change on Line 100A that results in 272' of pipe needing to be replaced. (49 CFR 192.611)	673,732	-35,518			-	-
GL-03164	NVL-1400 ClrkstJnct Vlv 1410S Repl	Holly	Replace 24" mainline launcher/receiver Valve 1410S at Clarkston Junction, Line 1400. Valve 1410S has been determined to be inoperable, both with actuation and manually. Long-term compliance with 49 CFR 192.745(b) requires replacement of the valve. Short-term and medium-term negative impacts to inspection on Line 1400.	165,813	1,141,811			-	-
GL-03166	KZO-1800 Schoolcraft CG Vlv Tap Repl	Schoolcraft	Replacement of two 8" tap valves, installation of two 8" check valves, and associated piping at Schoolcraft City Gate in support of CG rebuild and in order to improve gas deliverability.	6,402	0			-	-
GL-03178	KZO-1300 B Ave 1320 Repl	Plainwell	Replacement of inoperable valve 1320 at B Ave.	857,796	3,720			-	-
GL-03179	KZO-1300 Nazareth Rd CG Dual Tap Inst	Kalamazoo	Project from prior years (2022) final reconciliation	1,381,359	6,594			-	-
GL-03187	JXN-LN 2800 Vlv 2816 Repl	Ann Arbor	Replace 18" mainline sectionalizing Miller Valve Site, Line 2800. Valve 2816 has significant sealing issues and has caused isolation problems during planned outages.	-	1,749,620			-	-
GL-03196	JXN-Del Base Pipe Equip Issues	n/a	Final project reconciliation	87,171	0			-	-
GL-03198	NVL-LN 2800 Vlv 2818 Repl	South Lyon	Replace 18" mainline sectionalizing Sutton Rd Valve Site, Line 2800. Valve 2818 has significant sealing issues and has caused isolation problems during planned outages.	2,352	1,530,381			-	-
GL-03263	Ln1100 - Dorr to Mid Cal Vlv Inst	Dorr	Valve spacing study has indicated a new sectionalizing block valve is needed between Dorr and Middleville Caledonia VS on Line 1100. (49 CFR 192.179)	1,166	173,760			-	-
GL-03289	STC- 1500 Valve Spacing VS Inst	New Baltimore	Valve spacing study has indicated a new sectionalizing block valve is needed between St Clair and Macomb on Line 1500. (49 CFR 192.179)	1,940	177,253		1,159,265	-	836,761
GL-03290	NVL- 1400 Valve 1420N Repl	Northville	Replace 24" mainline launcher/receiver Valve 1420N at Northville Compressor Station, Line 1400. Valve 1420N has been determined to be inoperable, both with actuation and manually. Long-term compliance with 49 CFR 192.745(b) requires replacement of the valve. Short-term and medium-term negative impacts to inspection on Line 1400.	401	1,012,964			-	-
GL-03296	SAG-250 Mt. Pleasant CG Vlv Repl	Mt Pleasant	Two gas supply valves and one drain valve have been recommeded for replacement by operations. These valves have been identified as leaking by, and need to be replaced to allow for integrity inspections.	-	411,726			-	-
GL-03298	SAG-2100 Akron CG Vlv 2123 Act Repl	Akron	Valve 2114E and the actuator on Valve 2123 have been recommeded for replacement by operations. Valve 2114E has been identified as leaking by, and the actuator on valve 2123 has been identified as inoperable.	-	72,680			-	-
GL-03299	SAG-250 Pine Rvr to Zilwaukee VS Vlv Ins	Freeland	Valve spacing study has indicated a new sectionalizing block valve is needed between Pine River and Zilwaukee on Line 250. (49 CFR 192.179)	145	1,679,254			-	-

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GL-03300	NVL-2800 S Lyon Vlv Repl	South Lyon	Replacement of one 18" mainline valve, two 16" tap valves and associated piping at S Lyons-Whitmore Lake City Gate in support of CG rebuild and in order to improve gas deliverability.	-	4,157,707	815,965		588,966	226,999
GL-03302	OVS- 1100 Dorr CG Vlv Repl	Dorr	Replacement of one 24" mainline valve, two 4" tap valves and associated piping at Dorr City Gate in support of CG rebuild and in order to improve gas deliverability.	-	1,679,112			-	-
GL-03311	SAG-100C Valve Spacing VS	Mt Pleasant	Valve spacing study has indicated a new sectionalizing block valve is needed between Airport and Herrick on Line 100C. (49 CFR 192.179)	-	1,251,420			-	-
GL-03313	FDM 1100 Clintonia VS Vlv 1148 Repl and RCV	Portland	Valve 1148 at Clintonia VS has been recommeded for replacement by operations. This valve have been identified as leaking by, and needs to be replaced. This valve is also on the RCV program list and will become RCV capable at this time.		0		48,678	-	35,136
GL-03315	Line 2200 - Howell to Vector Hartland VS (Valve Site Installation due to valve spacing)	Howell	Valve spacing study has indicated a new sectionalizing block valve is needed between Howell and Vector Hartland on Line 2200. (49 CFR 192.179)		34,314	2,092,598		1,510,444	582,154
GL-03317	Line 1900 - Leonard-Lakeville CG - Valve 1936 & dual tap (1935 & 1937) replacements	Leonard	Replacement of one 26" mainline valve, two 12" tap valves and associated piping at Leonard-Lakeville City Gate in support of CG rebuild and in order to improve gas deliverability.		0		2,344,657	-	1,692,381
GL-03318	SAG 2060 Flint CG Branch Rd Vlv 260 Act Repl and 8GSV2 Repl	Flint	Valve 8GSV2 at Flint CG - Branch Rd has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced for integrity inspections. Valve 2060 has operator issues, valve in good condition but the operator does not engage.		0		561,420	-	405,235
GL-03319	Line 2800 - Grand Blanc Jct. 8GSV8 Replacement	Grand Blanc	The gas supply valve at Grand Blanc has been recommeded for replacement by operations. This valve have been identified as leaking by, and needs to be replaced to allow for integrity inspections.		0		287,200	-	207,302
GL-03320	STC 1600 Coolidge CG Vlv 1632 Repl	Royal Oak	Valve 1632 at Coolidge CG has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced to allow for isolation.		0		592,249	-	427,487
GL-03330	OVS-1100 139th Ave Pipe Repl	Shiwassee Co	Class Location Change for OVS Line 1100 139th Ave. Replace 1807' of 24" pipe	-	10,345			-	-
GL-03333	SAG Line 500 Jennings Rd Class Location Change Pipe Repl	Flint	Class location change on Line 500 that results in 326' of pipe needing to be replaced west of Jennings Rd crossing. (49 CFR 192.611)		44,663	16,352	1,434,378	11,803	1,039,888
GL-03336	SAG Line 100A Lake George Class Location Change Pipe Repl	Lake George	Class location change on Line 100A that results in 4466' of pipe needing to be replaced from Aurthur Rd crossing to south of Cedar Rd. (49 CFR 192.611) Compliance date of Dec 2024		44,663	11,417,414		8,241,127	3,176,287
(11132) GL-XXXXX	STC 1500 Shelby VS Vlv 1522 Repl	Shelby Twp	Valve 1522 at Shelby VS has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.				1,947,120	-	1,405,438

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(12247) GL-XXXXX	Line 1400 - Highland to Pontiac Trail VS (Valve Site Installation due to valve spacing)	Milford	Valve spacing study has indicated a new sectionalizing block valve is needed between Highland and Pontiac Trail on Line 1400. (49 CFR 192.179)			815,965		588,966	226,999
(12919) GL-XXXXX	STC Macomb VS Valve 1528 and 1526W Repl	Macomb	26" mainline sectionalizing Valve 1528 is inoperable in the open position. Long-term compliance with 49 CFR 192.745(b) requires replacement of the valve. Also operator issues have been identified on 26" 1526W; Short-term and medium-term negative impacts to outage execution and pipeline emergency response on Lines 1500 and 1700.				1,298,080	-	936,958
(13515) GL-XXXXX	Line 300 - Arthur Rd Vs to Wise Rd VS INST (Valve Site Installation due to valve spacing)	Harrison	Valve spacing study has indicated a new sectionalizing block valve is needed between Arthur Rd VS and Wise Rd VS on Line 300. (49 CFR 192.179)			-	1,622,600	-	1,171,198
(13521) GL-XXXXX	Line 300 - Gordonville to Zilwauke VS INST (Valve Site Installation due to valve spacing)	Midland	Valve spacing study has indicated a new sectionalizing block valve is needed between Gordonville and Zilwaukee on Line 300. (49 CFR 192.179)			1,572,200	-	1,134,819	437,381
(13522) GL-XXXXX	Line 3200 - Lansing Ave VS to M-106 VS INST (Valve Site Installation due to valve spacing)	Rives Junction	Valve spacing study has indicated a new sectionalizing block valve is needed between Lansing Ave and M-106 VS on Line 3200. (49 CFR 192.179)			2,043,860	-	1,475,265	568,595
(13700) GL-XXXX	FDM 400 Perry-Morrice Dual Tap Vlv. Inst.	Morrice	Perry-Morrice is a critical facility to improve the resiliency of. This site cannot take an outage at anytime in the year, and the load in fall, winter and spring is too high to reasonably supply temporary gas with a CNG or even LNG trailer. Installation of one 24" mainline valve, two 4" tap valves and associated piping at Perry Morrice City Gate in order to improve gas deliverability.				1,995,798	-	1,440,574
(13748) GL-XXXXX	Line 2800 - Bridgeport VS Drain Vlv Repl	Bridgeport	LR drain valve has been recommeded for replacement by operations. This valve has been identified as leaking by.				21,094	-	15,226
(9004) GL-XXXXX	NVL - Line 1400 - Highland CG - New 4" dual taps & piping	Highland	Replacement of two 4" tap valves, two 4" check valves, and associated piping at Highland City Gate in support of CG rebuild and in order to improve gas deliverability.			815,965		588,966	226,999
(9017) GL-XXXXX	Line 1800 - Schoolcraft CG - New 8" dual tap valves & piping	Schoolcraft	Replacement of two 8" tap valves, installation of two 8" check valves, and associated piping at Schoolcraft City Gate in support of CG rebuild and in order to improve gas deliverability.				79,507	-	57,388
(12334) GL-XXXXX	Line 300 - Muskegon River CS 301-T12 Replacement	Marion	Valve 301-T12 has been recommeded for replacement by operations. It has been identified as leaking by.				488,403	-	352,531
(12335) GL-XXXXX	Line 300 - Coleman Beaverton LR Drain Vlv Replacement	Coleman	The drain valve at Coleman Beaverton has been recommended for replacement by operations. One of the Drain Valves on the Launcher/Receiver at Coleman Beaverton Valve Site has been identified as causing issues during the integrity inspections.				21,094	-	15,226
(12920) GL-XXXXX	FDM 400 Laingsburg Int Vlv 401-24 Repl	Laingsburg	Valve 401-24 at Laingsburg Interconnect has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.				2,433,900	-	1,756,797
	TOTAL EXPENDITURE			**31,712,475**	**24,141,732**	**25,683,301**	**19,914,899**	**18,538,291**	**21,519,650**

Question:

130. Refer to WP-MPG-5, pages 1-2, Regulator Stations for Distribution program. For each of the following projects (GM-00891, GM-00931, GM-00933, GM- 00939, GM-00947, GM-00989 through GM-01026, 12892 down to 13781), please provide the following information:
a. The cost of the project by year from inception to completion.
b. Explain what is the problem and why the project is necessary?
c. What alternatives were evaluated and what financial benefits will result from completion of the project.
d. The phases of project development for each project with timeline and related cost and the phase that the project is currently in.
e. Explain why some projects do not have a GM prefix.

Response:

a. See attachment U-21490-AG-CE-0288-Griffin_ATT_1 for the cost by year from inception to completion for these projects.
b. See attachment U-21490-AG-CE-0288-Griffin_ATT_1 for the requested information.
c. See attachment U-21490-AG-CE-0288-Griffin_ATT_1 for the requested information.
d. See attachment U-21490-AG-CE-0288-Griffin_ATT_1 for the requested information.
e. GM prefixes are typically assigned to a project when the project enters the engineering and design phase, and expenditures commence.

Witness: MICHAEL P. GRIFFIN
Date: April 2, 2024

U-21490-AG-CE-0288-Griffin_ATT_1

Consumers Energy Company — Case No. U-21490

Actual & Projected Capital Expenditures for the Capacity/Deliverability Program — ~~WP-MPG-5~~

Regulator Stations-Distribution — Page 1 of 10

Project ID	Project Description	Reason for Project	2021 Actual	2022 Actual	2023 Projection	2024 Projection	2025 Projection	9 ME 9/30/2024 Projection	12 ME 9/30/2025 Projection
GM-00891	BC-63-066 Southgate Rbld	2022 Station rebuild	48,702	4,094,123	(99,114)			-	-
GM-00931	MAC-67-016 Selfridge Sta Rbld	2024 Station rebuild		15,745	24,698	2,932,637		2,299,501	633,136
GM-00933	SAG-63-034 State, Hemmeter Rbld	2024 Station rebuild		-	27,374	2,926,800		2,294,924	631,875
GM-00939	RO-67-074 9Mi, Vienna Rbld	2024 Station Rebuild		14,020	4,752	3,572,830		2,801,481	771,349
GM-00947	(12902) Center & Boltwood 64-305	2025 Station rebuild				-	3,492,200	-	2,738,259
GM-00989	FNT-66-073 2nd, Harrison Rbld	2024 piping modifications to de-risk low pressure distribution systems.		-	1,584	1,210,789		949,388	261,401
GM-00990	Lake Lansing & Rutherford 65-050	2024 Rebuild				2,506,614		1,965,454	541,160
GM-00992	WWN-68-155 8 Mi, Middlebelt Bldg Repl	Replace building at regulator station		-	1,160			-	-
GM-01001	LAN-Grand Rvr-Williamston Sta Rbld	2024 Rebuild		-	19,096	2,889,668		2,265,809	623,859
GM-01002	(12894) Ithaca 63-031	2024 Rebuild				2,696,100		2,114,031	582,069
GM-01026	(12997) Plainwell odorizer 64-505	2024 Rebuild				3,383,400		2,652,948	730,452

MICHIGAN PUBLIC SERVICE COMMISSION Case No: U-21490

U-21490-AG-CE-0288-Griffin_ATT_1
Consumers Energy Company
Actual & Projected Capital Expenditures for the Capacity/Deliverability Program
Regulator Stations-Distribution

Project ID	Project Description	Question	Present Phase	Comments on necessity for Project	Alternatives & finacial benefits
GM-00891	BC-63-066 Southgate Rbld	U21490-AG-CE-0288	Complete	Rebuild of regulator station which was beyond its designed lifespan. Installation of a bath heater, SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
GM-00931	MAC-67-016 Selfridge Sta Rbld	U21490-AG-CE-0288	Engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load including Selfridge Air Base. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
GM-00933	SAG-63-034 State, Hemmeter Rbld	U21490-AG-CE-0288	Approved for constructio	Rebuild of regulator station which was beyond its designed lifespan. Installation of a bath heater, SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
GM-00939	RO-67-074 9Mi, Vienna Rbld	U21490-AG-CE-0288	Pre-engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of a bath heater, SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Station located in the far southeast corner of our service territory where backfeed is not sufficient to retire this station. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
GM-00947	(12902) Center & Boltwood 64-305	U21490-AG-CE-0288	Pre-engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Mitigating risk of high pressure inlet pressure into single regulator cut to standard pressure system.	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration and replacing a station which has a direct cut from high pressure (~400 psig) directly to standard (< 1 psig) pressure system. Improved response and reliability with modern regulators.
GM-00989	FNT-66-073 2nd, Harrison Rbld	U21490-AG-CE-0288	Approved for constructio	Mitigating risk of high pressure inlet pressure into single regulator cut to standard pressure system.	Full retirement of station was considered, not feasible given modeled customer load. Benefits include replacing a station which has a direct cut from high pressure (~400 psig) directly to standard (< 1 psig) pressure system.
GM-00990	Lake Lansing & Rutherford 65-050	U21490-AG-CE-0288	Pre-engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
GM-00992	WWN-68-155 8 Mi, Middlebelt Bldg Repl	U21490-AG-CE-0288	Project cancelled	Project cancelled	Project cancelled
GM-01001	LAN-Grand Rvr-Williamston Sta Rbld	U21490-AG-CE-0288	Engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of a bath heater, SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
GM-01002	(12894) Ithaca 63-031	U21490-AG-CE-0288	Approved for constructio	Rebuild of regulator station which was beyond its designed lifespan. Installation of SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
GM-01026	(12997) Plainwell odorizer 64-505	U21490-AG-CE-0288	Engineering/design	Replacement of odorizer which has exceeded its design lifespan of 30 years. Installation of modern odorizer pump system for consistency and reliability enhancements.	Alternative to not mitigate the risk of 30 year old pump was considered but not pursued. Benefits include a modern odorizer system with a pump. Precise measuring and prompt monitoring for abnormal condition. Compliant odorization of a transmission line which requires odorization per CFR 192.625,

U-21490-AG-CE-0288-Griffin_ATT_1

Consumers Energy Company — Case No. U-21490

Actual & Projected Capital Expenditures for the Capacity/Deliverability Program — ~~WP-MPG-5~~

Regulator Stations-Distribution — Page 1 of 10

Project ID	Project Description	Reason for Project	2021 Actual	2022 Actual	2023 Projection	2024 Projection	2025 Projection	9 ME 9/30/2024 Projection	12 ME 9/30/2025 Projection
(12892) Hill & Center 66-025		2025 Station rebuild		0	0		3,003,900	-	2,355,379
(12899) Vienna and McKinley 66-137		2025 Station rebuild		0	0		2,035,850	-	1,596,324
(12904) 21 & Romeo Plank 67-048		2025 Station rebuild		0	0		3,492,200	-	2,738,259
(12905) Silver Lake & Dixie 67-007		2025 Station rebuild		0	0		3,492,200	-	2,738,259
(12906) Gardner & 7 Mile 68-015		2025 Station rebuild		0	0		3,492,200	-	2,738,259
(12907) Poseyville 63-245		2025 Station rebuild - includes 1 mile of HP main to relocate statio		0	0		5,088,200	-	3,989,693
(13780) Hogsback & Pryor 65-052		2025 Station rebuild		0	0		2,035,850	-	1,596,324
(13781) Central Odorant Facility		2025 Station rebuild		0	0		3,376,300	-	2,647,381

U-21490-AG-CE-0288-Griffin_ATT_1

Consumers Energy Company

Actual & Projected Capital Expenditures for the Capacity/Deliverability Program

Regulator Stations-Distribution

Project ID	Question	Present Phase	Comments on necessity for Project	Alternatives & finacial benefits
(12892) Hill & Center	U21490-AG-CE-0288	Pre-engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
(12899) Vienna and N	U21490-AG-CE-0288	Pre-engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
(12904) 21 & Romeo	U21490-AG-CE-0288	Engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of a bath heater, SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
(12905) Silver Lake 8	U21490-AG-CE-0288	Pre-engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
(12906) Gardner & 7	U21490-AG-CE-0288	Engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
(12907) Poseyville 63	U21490-AG-CE-0288	Pre-engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
(13780) Hogsback &	U21490-AG-CE-0288	Pre-engineering/design	Rebuild of regulator station which was beyond its designed lifespan. Installation of SCADA monitoring	Full retirement of station was considered, not feasible given modeled customer load. Benefits include protection from debris with station filration. Improved response and reliability with modern regulators.
(13781) Central Odor	U21490-AG-CE-0288	Pre-engineering/design	Construction of central facility for the bulk storage of odorant for delivery to statewide small odorizers. Factility for the rebuild and testing of rebuilt odorizer pumps prior to re-deployment.	The "take no action" alternative was considered. The existing below grade bulk storage tank at our Thetford site in Mt. Morris, Michigan is at the end of its design life and is a designed buried odorant tank.

Consumers Energy Company — Case No. U-21490
Actual & Projected Capital Expenditures for the Capacity/Deliverability Program — WP-MPG-5
Regulator Stations-Distribution —

Project ID	Project Description	Reason for Project	2022 Actual	2023 Projection	2024 Projection	2025 Projection	9 ME 9/30/2024 Projection	12 ME 9/30/2025 Projection
GM-00722	SAG-63-085 East, Railroad Rbld	Planned rebuild	421,888	(1,231)			0	0
GM-00791	FNT-66-079 Idaho, St John Trip-out Ret	Upgrade SCADA/RTU Electrical	703,498	2,453			-	-
GM-00809	WWN-68-146 Ford, Stacy Rbld	Planned 2021 rebuild	696,502				-	-
GM-00814	SAG-63-056 Green, Pacell Ret	Upgrade SCADA/RTU Electrical, replace emrg vlvs	1,223,811	5,822			-	-
GM-00840	RO-68-109 9 Mi, Greenfield Boiler Ret	Boiler replacement	492,080	339			-	-
GM-00842	WWN-68-017 5 Mi, Newburgh Boiler Ret	Boiler replacement	298,419	5,402			-	-
GM-00844	JXN-65-100 Brooklyn, US127 F-S Repl	2022 Filter/Separator installation	1,746,025	1,191			-	-
GM-00850	RO-67-199 Coolidge, Wattles Htr Inst	Boiler replacement	265,871	16,255			-	-
GM-00857	JXN-65-075 Chelsea, Manchester Rbld	Planned rebuild	3,990,929	18,718			-	-
GM-00858	GRV-67-022 Millville, Davison Ret	Install distribution main to allow for retirement of reg station	1,955,325				-	-
GM-00860	FNT-66-018 Indiana, Minnesota Ret	Deferred to 2023 - Rebuild of Valve nest, retirement of SP outlet	270,600	664	950,861		745,577	205,284
GM-00862	FNT-66-001 Center, E. Court Htr Inst	2023 New Heater	11,835	177,059			-	-
GM-00865	DE Ave. & 32nd St. Richland 64-083 - valve nest	Rebuild inlet/outlet valve assembly		0	787,246		617,285	169,961
GM-00866	NVL-New Hudson CG Odorizer Repl	2022 Odorizer Rebuild	3,503,518	17,495			-	-
GM-00868	JXN-65-105 River St Bldg Repl	2023 Building replacement	6,097	207,742			-	-
GM-00875	BC-63-007 10th, Trumbull Ret	Land for Columbus & Trumbull new station	125,414				-	-
GM-00876	BC-63-059 21st, Jefferson Rbld	2023 Rebuild	207,368	2,700,053			-	-
GM-00877	BC-63-170 N Water, Atlantic Inst	2022 New Regulator Station	5,970,597	13,809			-	-
GM-00891	BC-63-066 Southgate Rbld	2022 Station rebuild	4,094,123	(99,114)			-	-
GM-00897	(12896) Attica & Lake Pleasant 66-126	2024 Rebuild			2,628,716		2,061,195	567,521
GM-00908	ALM-63-032 Blanchard St Rbld	2022 Station rebuild	1,947,743	34,816			-	-
GM-00910	RO-67-045 Woodward, Nebraska Rbld	2022 Station rebuild	2,353,779	52,707			-	-
GM-00911	BC-63-XXX Trumbell, Columbus Inst	2023 Station rebuild	736,931	3,883,961			-	-
GM-00912	BA-63-096 Bayport Sta Rbld	2022 Station rebuild	1,912,614	53,625			-	-
GM-00916	GRN-65-331 Riverside Dr, Ionia Rbld	2023 Station rebuild	600,941	2,046,971			-	-
GM-00917	FNT-66-016 Montrose, Ridgeway Rbld	2023 Station rebuild	238,540	2,413,667			-	-
GM-00920	JXN-65-077 Ellery St Sta Mod	2022 Station Piping Rebuild	612,383	28,004			-	-
GM-00926	JXN-Jxn 24th St Sta Press Mod	2022 Station Piping Rebuild	531,782	108,428			-	-
GM-00928	ALM-63-124 Cedar Lake Sta Rbld	2023 Station rebuild	21,544	2,595,719			-	-
GM-00931	MAC-67-016 Selfridge Sta Rbld	2024 Station rebuild	15,745	24,698	2,932,637		2,299,501	633,136
GM-00932	KZO-64-021 Pitcher, Lovell Ret	2024 Station rebuild	12,857		593,750	-	465,564	128,186
GM-00933	SAG-63-034 State, Hemmeter Rbld	2024 Station rebuild	-	27,374	2,926,800		2,294,924	631,875
GM-00935	LAN-65-016 Verlinden Sta Rbld	2023 Station rebuild	9,929	2,872,552			-	-

Consumers Energy Company — Case No. U-21490
Actual & Projected Capital Expenditures for the Capacity/Deliverability Program — WP-MPG-5
Regulator Stations-Distribution — Page 2 of 10

Project ID	Project Description	Reason for Project	2022 Actual	2023 Projection	2024 Projection	2025 Projection	9 ME 9/30/2024 Projection	12 ME 9/30/2025 Projection
GM-00938	MAC-11 Mile, Grosebeck Rbld	Replace building at regulator station	-	191,005			-	-
GM-00939	RO-67-074 9Mi, Vienna Rbld	2024 Station Rebuild	14,020	4,752	3,572,830		2,801,481	771,349
GM-00947	(12902) Center & Boltwood 64-305	2025 Station rebuild			-	3,492,200	-	2,738,259
GM-00948	MAR-64-345 Marshall, Butterfield Rbld	2023 Station rebuild	12,113	2,712,452			-	-
GM-00949	STC-St Clair Sta Odorizer Rbld	2023 Odorizer rebuild	49,365	2,823,318			-	-
GM-00952	MAR-64-351 Kzoo, Leggitt Odorizer Inst	Add pressure limiting valve to resolve OPP protection	21,286	317,145			-	-
GM-00962	LAN-65-035 Mt Hope, Marion Vlv Repl	2022 Inlet/outlet valve replacement	682,894	(356)			-	-
GM-00963	MAC-67-024 9 Mi, Piper Vlv Repl	2022 Inlet/outlet valve replacement	620,980	35,828			-	-
GM-00980	FNT-66-066 Chicago Blvd Sta Rbld	2023 Station rebuild	-	2,660,683			-	-
GM-00984	FNT-66-598 2 Temporary Odorizer Trailer	Procurement of mobile odorization injection equipment	-	651,488			-	-
GM-00986	WWN-68-019 7 Mi, Newburgh Heat Exch Rep	2024 replacement of heat exchanger	7,343	7,706	626,050		490,890	135,160
GM-00989	FNT-66-073 2nd, Harrison Rbld	2024 piping modifications to de-risk low pressure distribution systems.	-	1,584	1,210,789		949,388	261,401
GM-00990	Lake Lansing & Rutherford 65-050	2024 Rebuild			2,506,614		1,965,454	541,160
GM-00992	WWN-68-155 8 Mi, Middlebelt Bldg Repl	Replace building at regulator station	-	1,160			-	-
GM-01001	LAN-Grand Rvr-Williamston Sta Rbld	2024 Rebuild	-	19,096	2,889,668		2,265,809	623,859
GM-01002	(12894) Ithaca 63-031	2024 Rebuild			2,696,100		2,114,031	582,069
GM-01026	(12997) Plainwell odorizer 64-505	2024 Rebuild			3,383,400		2,652,948	730,452
(12251) Install gas distribution main to be able to retire station		Install distribution main to allow for retirement of reg station			1,002,000	1,002,000	785,675	1,002,000
(13009) Rebuild regulator stations heaters 2023-32		Replace or add water bath heater at a regulator station			1,587,545	1,182,190	1,244,805	1,269,703
(13010) Regulator station building replacements 2023-2033		Replace building at regulator station			1,986,205	2,395,900	1,557,397	2,307,450
(13188) 65-128 Chestnut & Main *****HPSP******		2024 piping modifications to de-risk low pressure distribution systems.			591,095		463,482	127,613
(13763) Honeywell Pressure Monitor Equipment install		Installation of remote pressure monitoring equipment	0	250,002	237,500	237,500	186,225	237,500
(12892) Hill & Center 66-025		2025 Station rebuild	0	0		3,003,900	-	2,355,379
(12899) Vienna and McKinley 66-137		2025 Station rebuild	0	0		2,035,850	-	1,596,324
(12904) 21 & Romeo Plank 67-048		2025 Station rebuild	0	0		3,492,200	-	2,738,259
(12905) Silver Lake & Dixie 67-007		2025 Station rebuild	0	0		3,492,200	-	2,738,259
(12906) Gardner & 7 Mile 68-015		2025 Station rebuild	0	0		3,492,200	-	2,738,259
(12907) Poseyville 63-245		2025 Station rebuild - includes 1 mile of HP main to rel	0	0		5,088,200	-	3,989,693
(13780) Hogsback & Pryor 65-052		2025 Station rebuild	0	0		2,035,850	-	1,596,324
(13781) Central Odorant Facility		2025 Station rebuild	0	0		3,376,300	-	2,647,381
GM-95031	JXN-BMS Retro Fit RS Inst	Retrofit of approximately 12 existing heaters with Burner Managment systems	-	156,291	219,330	226,100	171,978	224,638
SCADA PROJECTS TOTAL - See Page 3 for Detail			3,738,874	402,637	2,095,750	2,095,750	1,643,292	2,095,750
EMERGENT BREAK FIX TOTAL - See Pages 4 - 8 for Detail			3,160,105	3,899,783	3,000,000	3,000,000	2,352,321	3,000,000
MISCELLANEOUS TOTAL - See Pages 9 - 10 for Detail			(221,383)	127,067	-	-		-
TOTAL PROGRAM EXPENDITURES			**43,064,283**	**31,470,820**	**38,424,884**	**39,648,340**	**30,129,222**	**39,384,204**

U21490-AG-CE-0291
Page **1** of **1**

Question:

133. Refer to WP-MPG-6, pages 1-2, City Gate projects. For each of the following projects (GM-00941, GM-00942, GM-00943, GM-00944, GM-00951, GM-009994, GM-00996, 11181 down to 13204, 13231 to 13236, and 13142), please provide the following information:
a. The cost of the project by year from inception to completion.
b. Explain what is the problem and why the project is necessary?
c. What alternatives were evaluated and what financial benefits will result from completion of the project.
d. The phases of project development for each project with timeline and related cost and the phase that the project is currently in.
e. Explain why some projects do not have a GM prefix.

Response:

a. See attachment U-21490-AG-CE-0291-Griffin_ATT_1 which contains the cost of the above listed project from inception to completion.

b. See attachment U-21490-AG-CE-0291-Griffin_ATT_1 which contains the reason each project is necessary.

c. Alternatives to a full rebuild are considered during the scoping stages and during the annual financial planning stage. Alternatives include scope reduction to a partial project, focusing on the specific equipment requiring modernization or updating due to age. For example, Dorr CG rebuild was originally a planned rebuild, however due to the asset's property and state of the existing equipment, was reduced in scope to a partial project which resulted in cost savings. Not every site has equipment and site properties which allow for reduction in scope, however, every project is evaluated and discussions concerning these options take place during the scoping phase of the project. Additional alternatives include aligning projects cross-functionally with other programs and projects to share costs, lowering the overall cost, or grouping similar projects by area and going out to bid in groups. Outdated equipment at City Gates results in increased risk of equipment failure. Modern facilities have more reliable and efficient equipment, resulting in improved reliability, less safety risk and less maintenance.

d. These projects are typically installed between May and November, as this is when the Company can sectionalize areas of the system to perform work of this nature; however, it must be coordinated with other outages and work on the system, so specific installation times are not known at this time. Additionally, pipeline integrity inspections and remediation outage windows need to first be determined before the project outages can occur. Projected timeframes for each project component are shown in the attached.

e. A GM prefix is one of the Company's project ID types, which is assigned once project engineering is kicked off and a work order is created. Available GM numbers have been added to the workpaper.

Witness: MICHAEL P. GRIFFIN
Date: April 3, 2024

U-21490-AG-CE-0291-Griffin_ATT_1
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity/Deliverability Program
City Gate Projects

Project ID	Project Description	Order	Location	Reason for Project	2022 Actual	2023 Projection	2024 Projection	2025 Projection
GM-00941	OVS-Dorr CG Rbld	39997759	Dorr	Planned **2024** rebuild	255,490	454,458	3,200,000	250,000
GM-00942	KZO- Galesburg CG Rbld	40213320	Kalamazoo	Planned **2024** rebuild	167,840	1,756,562	3,813,600	250,000
GM-00943	STC-Orion CG Rbld	39924024	Lake Orion	2024 construction project	16,680	867,395	11,269,623	250,000
GM-00944	JXN-Park Rd CG ESD Inst	41700070	Jackson	2024 construction project	-	18,532	1,055,000	33,000
GM-00951	JXN-PEPL-Blissfield CG Rbld	40187839	Riga	Planned 2024 rebuild	15,364	426,812	10,172,574	250,000
GM-00994	STC-Leonard-Lakeville City Gate Rbld	41317268	Leonard	Planned 2024 Rebuild	-	589,673	7,852,203	250,000
GM-00996	FDM-Bancroft CG Rbld	41332319	Morrice	Planned 2025 Rebuild	-	167,332	500,000	8,524,000
GM-01055 (11181) Flint Torrey city gate rebuild	Flint Torrey city gate rebuild		Flint	Planned 2025 rebuild			700,000	4,750,000
GM-01061 (11184) Laingsburg CG ESD Valve	Laingsburg CG ESD Valve		Laingsburg	Planned 2025 Modernization			33,000	1,055,000
(11189) Spring Arbor CG and odorizer rebuild	Spring Arbor CG and odorizer rebuild		Spring Arbor	2026 construction project				500,000
GM-00997 (13197) Lahser CG ESD Valve	Lahser CG ESD Valve		Beverly Hills	Planned 2025 Project			33,000	1,055,000
GM-01054 (13200) Hanover Horton CG and odorizer	Hanover Horton CG and odorizer rebuild		Horton	2025 construction project			500,000	8,455,000
GM-01052 (13201) Jackson Hart PEPL CG and odoriz	Jackson Hart PEPL CG and odorizer rebuild		Jackson	2025 construction project			500,000	8,555,000
GM-01056 (13203) Highland CG and odorizer rebuild	Highland CG and odorizer rebuild		Highland	2025 construction project			500,000	8,555,000
(13786) GL-03398 / Excelcior CG Pipeline Install	Excelcior CG Pipeline Install		Kalkaska	Planned 2024 Project		100,000	5,985,000	250,000
(13204) Macomb CG ESD Valve	Macomb CG ESD Valve		Macomb	2025 construction project			33,000	1,098,000
(13231) Flint Irish CG & Odorizer rebuild	Flint Irish CG & Odorizer rebuild		Grand Blanc	2026 construction project				800,000
(13232) Schoolcraft CG & Odorizer rebuild	Schoolcraft CG & Odorizer rebuild		Schoolcraft	2026 construction project				500,000
(13233) Climax CG - PEPL & Odorizer rebuild	Climax CG - PEPL & Odorizer rebuild		Climax	2026 construction project				800,000
(13234) South Lyon - Whitmore Lake CG & Odorizer r	South Lyon - Whitmore Lake CG & Odorizer rebuild		South Lyon	2026 construction project				500,000
(13235) Dixie Waterford ESD Valve	Dixie Waterford ESD Valve		Clarkston	2026 construction project				40,000
(13236) Mid-Cal ESD Valve	Mid-Cal ESD Valve		Middleville	2026 construction project				40,000
GC-00124 (13142) Overisel Compression Station RTU/Electrical Upgrade	Overisel Compression Station RTU/Electrical Upgra		Overisel	2025 RTU-Elect Upgrade			250,000	2,850,000

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City Gate Projects					
Project ID	2026 Amount	2027 Amount	9 Months Ending 9/30/2024 Projection	12 Months Ending 9/30/2025 Projection	b. Explain what is the problem and why the project is necessary
GM-00941	-	-	2,498,921	896,307	59 year old facility at the end of its designed life.
GM-00942	-	-	2,978,089	1,030,739	61 year old facility at the end of its designed life.
GM-00943	-	-	8,800,593	2,664,258	69 year old facility at the end of its designed life.
GM-00944	-	-	823,863	256,907	Installation of fail closed ESD valves for enhanced overpressure protection.
GM-00951	-	-	7,943,893	2,423,909	Installation of new city gate to serve our existing customers. Resolution to MPSC Case No 6452 and Consumers Energy commitment to own, operate and maintain the overpressure protection device which protects our distribution system.
GM-00994	-	-	6,131,886	1,915,545	54 year old facility at the end of its designed life.
GM-00996	250,000	-	390,456	6,766,044	62 year old facility at the end of its designed life.
GM-01055 (11181) Flint Torrey city gate rebuild	250,000	-	546,639	3,862,697	60 year old facility at the end of its designed life.
GM-01061 (11184) Laingsburg CG ESD Valve	33,000	-	25,770	831,093	Installation of fail closed ESD valves for enhanced overpressure protection.
(11189) Spring Arbor CG and odorizer rebuild	8,740,000	250,000	-	390,456	63 year old facility at the end of its designed life.
GM-00997 (13197) Lahser CG ESD Valve	33,000	-	25,770	831,093	Installation of fail closed ESD valves for enhanced overpressure protection.
GM-01054 (13200) Hanover Horton CG and odorizer	250,000	-	390,456	6,712,161	61 year old facility at the end of its designed life.
GM-01052 (13201) Jackson Hart PEPL CG and odori	250,000	-	390,456	6,790,253	56 year old facility at the end of its designed life.
GM-01056 (13203) Highland CG and odorizer rebuil	250,000	-	390,456	6,790,253	62 year old facility at the end of its designed life.
(13786) GL-03398 / Excelcior CG Pipeline Install	-	-	4,673,763	1,506,465	Installation of 6 miles of 6" plastic medium pressure pipeline to enable the retirement of Excelcior city gate. Customer load will be uniterrupted and fed by the recently rebuilt Bear Lake City Gate
(13204) Macomb CG ESD Valve	33,000	-	25,770	864,672	Installation of fail closed ESD valves for enhanced overpressure protection.
(13231) Flint Irish CG & Odorizer rebuild	8,740,000	250,000	-	624,730	51 year old facility at the end of its designed life.
(13232) Schoolcraft CG & Odorizer rebuild	8,740,000	250,000	-	390,456	55 year old facility at the end of its designed life.
(13233) Climax CG - PEPL & Odorizer rebuild	8,740,000	250,000	-	624,730	44 year old facility at the end of its designed life.
(13234) South Lyon - Whitmore Lake CG & Odorizer	8,740,000	250,000	-	390,456	68 year old facility at the end of its designed life.
(13235) Dixie Waterford ESD Valve	1,082,000	40,000	-	31,237	Installation of fail closed ESD valves for enhanced overpressure protection.
(13236) Mid-Cal ESD Valve	1,082,000	40,000	-	31,237	Installation of fail closed ESD valves for enhanced overpressure protection.
GC-00124 (13142) Overisel Compression Station RTU/Electrical Upgrade	150,000	-	195,228	2,280,373	Sixnet is no longer available, and are not API compliant.

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		Engineering/design		Construction		Closeout/punchlist	
Project ID	**Current Phase**	**Approx. Date**	**Approx. Cost**	**Approx. Date**	**Approx. Cost**	**Approx. Date**	**Approx. Cost**
GM-00941	Engineering/Design	May 2023-April 2024	415,995	Apr 2024-Nov 2024	2,703,966	July 2024-Jan 2025	1,039,987
GM-00942	Engineering/Design	May 2023-April 2024	598,800	Apr 2024-Nov 2024	3,892,201	July 2024-Jan 2025	1,497,000
GM-00943	Engineering/Design	March 2023-Jan 2024	1,240,370	Apr 2024-Nov 2024	8,062,403	July 2024-Jan 2025	3,100,924
GM-00944	Engineering/Design	June 2023-May 2024	110,653	Apr 2024-Nov 2024	719,246	July 2024-Jan 2025	276,633
GM-00951	Engineering/Design	April 2023-May 2024	1,086,475	Apr 2024-Nov 2024	7,062,088	July 2024-Jan 2025	2,716,188
GM-00994	Engineering/Design	April 2023-July 2024	869,188	Apr 2024-Nov 2024	5,649,719	July 2024-Jan 2025	2,172,969
GM-00996	Engineering/Design	April 2024-July 2025	919,133	Apr 2025-Nov 2025	6,136,866	July 2025-Jan 2026	2,360,333
GM-01055 (11181) Flint Torrey city gate rebuild	Engineering/Design	Jan 2024-July 2025	570,000	Apr 2025-Nov 2025	3,705,000	July 2025-Jan 2026	1,425,000
GM-01061 (11184) Laingsburg CG ESD Valve	Engineering/Design	April 2024-July 2025	112,100	Apr 2025-Nov 2025	728,650	July 2025-Jan 2026	280,250
(11189) Spring Arbor CG and odorizer rebuild	Pre-Engineering/Design	Oct 2024-July 2025	949,000	Apr 2025-Nov 2025	6,168,500	July 2025-Jan 2026	2,372,500
GM-00997 (13197) Lahser CG ESD Valve	Engineering/Design	April 2024-July 2025	112,100	Apr 2025-Nov 2025	728,650	July 2025-Jan 2026	280,250
GM-01054 (13200) Hanover Horton CG and odorizer	Engineering/Design	April 2024-July 2025	920,500	Apr 2025-Nov 2025	5,983,250	July 2025-Jan 2026	2,301,250
GM-01052 (13201) Jackson Hart PEPL CG and odori	Pre-Engineering/Design	April 2024-July 2025	930,500	Apr 2025-Nov 2025	6,048,250	July 2025-Jan 2026	2,326,250
GM-01056 (13203) Highland CG and odorizer rebuil	Engineering/Design	April 2024-July 2025	930,500	Apr 2025-Nov 2025	6,048,250	July 2025-Jan 2026	2,326,250
(13786) GL-03398 / Excelcior CG Pipeline Install	Engineering/Design	May 2023-July 2024	633,500	Apr 2024-Nov 2024	4,117,750	July 2024-Jan 2025	1,583,750
(13204) Macomb CG ESD Valve	Engineering/Design	April 2024-July 2025	116,400	Apr 2025-Nov 2025	756,600	July 2025-Jan 2026	291,000
(13231) Flint Irish CG & Odorizer rebuild	Pre-Engineering/Design	April 2025-July 2026	979,000	Apr 2026-Nov 2026	6,363,500	July 2026-Jan 2027	2,447,500
(13232) Schoolcraft CG & Odorizer rebuild	Pre-Engineering/Design	April 2025-July 2026	949,000	Apr 2026-Nov 2026	6,168,500	July 2026-Jan 2027	2,372,500
(13233) Climax CG - PEPL & Odorizer rebuild	Pre-Engineering/Design	April 2025-July 2026	979,000	Apr 2026-Nov 2026	6,363,500	July 2026-Jan 2027	2,447,500
(13234) South Lyon - Whitmore Lake CG & Odorizer r	Pre-Engineering/Design	April 2025-July 2026	949,000	Apr 2026-Nov 2026	6,168,500	July 2026-Jan 2027	2,372,500
(13235) Dixie Waterford ESD Valve	Pre-Engineering/Design	April 2025-July 2026	116,200	Apr 2026-Nov 2026	755,300	July 2026-Jan 2027	290,500
(13236) Mid-Cal ESD Valve	Pre-Engineering/Design	April 2025-July 2026	116,200	Apr 2026-Nov 2026	755,300	July 2026-Jan 2027	290,500
GC-00124 (13142) Overisel Compression Station RTU/Electrical Upgrade	Engineering/Design	Jan 2024-July 2025	325,000	Apr 2025-Nov 2025	2,112,500	July 2025-Jan 2026	812,500

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Project ID	Project Description	Order	Location	Reason for Project	2022 Actual	2023 Projection	2024 Projection	2025 Projection	9 Months Ending 9/30/2024 Projection	12 Months Ending 9/30/2025 Projection
GM-00514	STC-Greenfield CG Rbld	31336816	Royal Oak	Planned 2022 rebuild	6,340,439	103,094			-	-
GM-00794	KZO-M Ave CG Rbld	40116346	Oshtemo	Planned 2022 rebuild	647,729	11,683,729	50,000		39,046	10,954
GM-00863	NVL-Novi-Wixom CG ESD, F-S Inst	38925689	Novi	Filter Seperator Install	361,490	(120,513)		130,000	-	101,519
GM-00864	STC-Goodison CG ESD Inst	39777530	Rochester	Planned 2022 rebuild	811,394	1,025			-	-
GM-00867	FDM-Lansing CG-Airport Rd Rbld	39140340	Lansing	Planned 2022 rebuild	8,082,082	(35,884)			-	-
GM-00898	MAR-Bear Lk Twp CG Rbld	38520942	Kalkaska	Planned 2022 rebuild	4,094,765	(3,209)			-	-
GM-00899	SAG-Akron CG Rbld	38622661	Akron	Planned 2022 rebuild	2,585,887	7,762,704	50,000		39,046	10,954
GM-00900	JXN-Napoleon-Brooklyn CG Rbld	38737039	Napoleon	Planned 2022 rebuild	6,275,876	29,698			-	-
GM-00901	STC-Rochester CG Rbld	38513343	Rochester	Planned 2022 rebuild	7,499,386	(81,257)			-	-
GM-00902	KZO-Kzo CG-Nazareth Rd Rbld	38862469	Kalamazoo	Planned 2022 rebuild	5,784,883	69,208			-	-
GM-00936	MAR-Excelsior Twp CG Ret-Vlv Inst	41338270	Kalkaska	Planned 2024 Project	-	55,448			-	-
GM-00941	OVS-Dorr CG Rbld	39997759	Dorr	Planned 2022 rebuild	255,490	454,458	3,200,000	250,000	2,498,921	896,307
GM-00942	KZO- Galesburg CG Rbld	40213320	Kalamazoo	Planned 2022 rebuild	167,840	1,756,562	3,813,600	250,000	2,978,089	1,030,739
GM-00943	STC-Orion CG Rbld	39924024	Lake Orion	2024 construction project	16,680	867,395	11,269,623	250,000	8,800,593	2,664,258
GM-00944	JXN-Park Rd CG ESD Inst	41700070	Jackson	2024 construction project	-	18,532	1,055,000	33,000	823,863	256,907
GM-00951	JXN-PEPL-Blissfield CG Rbld	40187839	Riga	Planned 2024 rebuild	15,364	426,812	10,172,574	250,000	7,943,893	2,423,909
GM-00955	SAG M&R Temp Skid 2 Valve Repl	39995890	Various	Planned 2022 rebuild	58,205	24,200			-	-
GM-00956	JXN-Reg Trailer 1 Build	40191448	Various	Planned 2023	470,250	204,517			-	-
GM-00957	JXN-Reg Trailer 2 Build	40191455	Various	Planned 2023	169,976	40,250			-	-
GM-00958	JXN-Reg Trailer 3 Build	40191453	Various	Planned 2023	243,321	47,226			-	-
GM-00959	JXN-Reg Trailer 4 Build	40191452	Various	Planned 2023	163,115	30,820			-	-
GM-00960	JXN-Reg Trailer 5 Build	40191450	Various	Planned 2023	186,197	33,250			-	-
GM-00965	KZO-M Ave CG F-S Install	40116897	Oshtemo	Planned 2022 rebuild	1,130,961	18,098			-	-
GM-00966	KZO-Climax CG Valve Repl	40563617	Climax	Planned 2022 rebuild	4,926	22,597			-	-
GM-00976	ALM-St. Louis VS RTU, Bldg Rep	40019478	St Louis	RTU-Elect Upgrade	-	1,366,910			-	-
GM-00979	STC-Pontiac Wlton CG ESD Inst	40645212	Auburn Hills	Planned 2023 Rebuild	33,234	948,293	-		-	-
GM-00994	STC-Leonard-Lakeville City Gate Rbld	41317268	Leonard	Planned 2024 Rebuild	-	589,673	7,852,203	250,000	6,131,886	1,915,545
GM-00996	FDM-Bancroft CG Rbld	41332319	Morrice	Planned 2025 Rebuild	-	167,332	500,000	8,524,000	390,456	6,766,044
GM-00997	STC-Lasher CG ESD Vlv Inst	41332540	Beverly Hills	Planned 2025 Project	-	29,071			-	-
GM-00999	STC- Pontiac Walton CG Cat Htr Repl	41345968	Auburn Hills	Planned 2024	-	44,000			-	-
GM-01000	STC-Metamora CG Cat Htr Inst	41345973	Oxford	Planned 2024	-	10,900			-	-
GM-01004	FDM-Dexter CG Reg Repl	41424130	Dexter	Planned 2024	-	48,299			-	-
GM-01005	JXN-Grasslake CG Fence Driveway Inst	41382682	Grass Lake	Project cancelled in 2023	-	600			-	-
GM-01006	OVS-Mid-Cal CG Vlv Repl	41564527	Middleville	Carry over from prior yea	-	22,213			-	-
(11181) Flint Torrey city gate rebuild			Flint	Planned 2025 rebuild			700,000	4,750,000	546,639	3,862,697
(11184) Laingsburg CG ESD Valve			Laingsburg	Planned 2025 Modernization			33,000	1,055,000	25,770	831,093
(11189) Spring Arbor CG and odorizer rebuild			Spring Arbor	2026 construction project				500,000	-	390,456
(13197) Lahser CG ESD Valve			Beverly Hills	Planned 2024 Project			33,000	1,055,000	25,770	831,093
(13200) Hanover Horton CG and odorizer rebuild			Horton	2025 construction project			500,000	8,455,000	390,456	6,712,161
(13201) Jackson Hart PEPL CG and odorizer rebuild			Jackson	2025 construction project			500,000	8,555,000	390,456	6,790,253
(13203) Highland CG and odorizer rebuild			Highland	2025 construction project			500,000	8,555,000	390,456	6,790,253
(13786) GL-03398 / Excelcior CG Pipeline Install			Kalkaska	Planned 2024 Project		100,000	5,985,000	250,000	4,673,763	1,506,465
(13204) Macomb CG ESD Valve			Macomb	2025 construction project			33,000	1,098,000	25,770	864,672

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Project ID	Project Description	Order	Location	Reason for Project	2022 Actual	2023 Projection	2024 Projection	2025 Projection	9 Months Ending 9/30/2024 Projection	12 Months Ending 9/30/2025 Projection
(13229) ZILWAUKEE CG (Z-1) RTU/Electrical Upgrade			Saginaw	RTU-Elect Upgrade			380,000	20,000	296,747	98,871
(13231) Flint Irish CG & Odorizer rebuild			Grand Blanc	2026 construction project				800,000	-	624,730
(13232) Schoolcraft CG & Odorizer rebuild			Schoolcraft	2026 construction project				500,000	-	390,456
(13233) Climax CG - PEPL & Odorizer rebuild			Climax	2026 construction project				800,000	-	624,730
(13234) South Lyon - Whitmore Lake CG & Odorizer rebuild			South Lyon	2026 construction project				500,000	-	390,456
(13235) Dixie Waterford ESD Valve			Clarkston	2026 construction project				40,000	-	31,237
(13236) Mid-Cal ESD Valve			Middleville	2026 construction project				40,000	-	31,237
(13788) City Gate Emergent Work			Various	Replacements for Capital Emergent Failures				500,000	-	390,456
GM- 95524 (13792) North Bradley RTU/Electrical Upgrade			Coleman	RTU-Elect Upgrade			369,000	20,000	288,157	96,461
GM- 95524 (13793) Wilson Rd VS RTU/Electrical Upgrade			Otisville	RTU-Elect Upgrade			369,000	20,000	288,157	96,461
GM-95524 (13794) James Township RTU/Electrical Upgrade			Saginaw	RTU-Elect Upgrade			369,000	20,000	288,157	96,461
(13798) Macomb Jct VS RTU/Electrical Upgrade			Macomb	RTU-Elect Upgrade			-	378,000	-	295,185
(13242) MT. PLEASANT CG (M-9) RTU Upgrade & BMS			Mt Pleasant	RTU-Elect Upgrade			-	383,000	-	299,090
GM-95224 (13208) FLINT BRANCH RD (F-2) RTU/Electrical Upgrade & BMS			Flint	RTU-Elect Upgrade			194,000	20,000	151,497	58,121
(13142) Overisel Compression Station RTU/Electrical Upgrade			Overisel	RTU-Elect Upgrade			250,000	2,850,000	195,228	2,280,373
(13180) Grand Blanc Interchange & Junction RTU/Electrical Upgrade			Grand Blanc	RTU-Elect Upgrade			378,000	20,000	295,185	98,433
(13218) NORTHVILLE COMPRESSOR STATION RTU UPGRADE RTU/Electrical			Northville	RTU-Elect Upgrade				250,000	-	195,228
(13182) MANCHESTER (PEPL) (MP-1) RTU/Electrical Upgrade			Manchester	RTU-Elect Upgrade		44,000	-	-	-	-
(13183) PINCONNING 18 TMS RTU/Electrical Upgrade			Pinconning	RTU-Elect Upgrade		53,000			-	-
(13184) SALEM (S-2) RTU Upgrade & BMS			Northville	RTU-Elect Upgrade		53,000	-	383,000	-	299,090
GM-95011	KZO FreeportCG -RTU upgrade	36301970	Freeport	2021 Carryover RTU	10,038	-			-	-
GM-95011	FDM-Tecumseh- RTU Upgrade	36364845	Tecumseh	2021 Carryover RTU	9,710	6,798			-	-
GM-95011	STC Metamora CG-RTU Upgrade	36400240	Oxford	2021 Carryover RTU	10,123	-			-	-
GM-95011	KZO Comstock-RTU Upgrade	36400241	Kalamazoo	2021 Carryover RTU	9,001	-			-	-
GM-95011	SAG Alma CG -RTU Updgrades	36889470	Alma	2021 Carryover RTU	203,797	(4,837)			-	-
GM-95011	SAG Birch Run - RTU Upgrades	36889472	Birch Run	2021 Carryover RTU	10,156	2,762			-	-
GM-95011	SAG Bridgeport CG -RTU Upgrades	36889474	Birch Run	2021 Carryover RTU	7,366	-			-	-
GM-95011	SAG Clilo CG - RTU Updgrade	36889478	Clio	2021 Carryover RTU	23,210	-			-	-
GM-95011	FDM Grass Lake CG -RTU Upgrade	36889479	Grass Lake	2021 Carryover RTU	32,167	1,939			-	-
GM-95011	FDM Jackson Park CG - RTU Upgrade	36889645	Jackson	2021 Carryover RTU	11,294	9,299			-	-
GM-95011	FDM Pinckney CG -RTU Upgrade	36889646	Pinckney	2021 Carryover RTU	15,018	-			-	-
GM-95011	STC Red Run CG-RTU Upgrade	36889649	Sterling Heights	2021 Carryover RTU	8,049	9,554			-	-
GM-95011	SAG Saginaw CG- RTU Upgrade	36889741	Saginaw	2021 Carryover RTU	48,374	9,817			-	-
GM-95011	West Wayne CG - RTU Upgrade	36889749	Farmington Hills	2021 Carryover RTU	9,287	-			-	-
GM-95011	FDM Williamston CG -RTU Upgrade	36889754	Williamston	2021 Carryover RTU	4,963	-			-	-
GM-95011	FDM Vector Leslie - RTU Upgrade	36889756	Leslie	2021 Carryover RTU	15,157	12,884			-	-
GM-95011	KZO River Lateral -RTU Upgrade	36889977	Kalamazoo	2021 Carryover RTU	6,355	-			-	-
GM-95011	SAG Flint Lapeer CG - RTU Upgrade	36889979	Davidson	2021 Carryover RTU	55,600	-			-	-
GM-95011	STC- SCADA Trailer Instal	38257732	Mobile Unit	2021 Carryover RTU	59,417	-			-	-
GM-95011	NVL- SCADA Trailer Instal	38263722	Mobile Unit	2021 Carryover RTU	63,241	1,026			-	-
GM-95011	STC-Shelby CG RTU-Replacement and Elect	38496556	Shelby Charter	2021 Carryover RTU	(6,124)	-			-	-
GM-95014	BUCKEYE 36 TMS (B 7) RTU Install	39064697	Beaverton	2022 RTU Repl/Electrical	1,268	-			-	-
GM-95014	Winterfield 29-TMS RTU Install	39065140	Marion	2022 RTU Repl/Electrical	1,125	-			-	-
GM-95014	ROSE CENTER (R 3) RTU Install	39065141	Holly	2022 RTU Repl/Electrical	435,203	2,312			-	-

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Question:

135. Refer to WP-MPG-8, page 1, for PLD projects. Please provide the following information:
a. For project GL-01656:
i. Explain what is the problem and why the project is necessary?
ii. What alternatives were evaluated and what financial benefits will result from completion of the project.
iii. Provide the phases of project development with timeline and related cost and the phase that the project is currently in.
b. Provide a list of the PLD projects completed each year 2021 and 2023 actual with related capital spending in Excel.

Response:

a.

i. The problem that is being addressed with GL-01656 is there is an MAOP difference between two interconnected pipelines on our system. The PLD project would address that MAOP difference and insure that MAOP is not exceeded.

ii. The other alternative would be to replace a large segment of pipeline with a higher MAOP that would eliminate the MAOP gap. This project is not being done for any financial benefit but rather to address a regulatory gap (MAOP Gap) and increase system safety and reliability.

iii. These projects are typically installed between May and November in the years shown on my workpaper WP-MPG-8, as this is when the Company can sectionalize areas of the system to perform work of this nature. However, it must be coordinated with other outages and work on the system. Specific installation dates will be known by the end of the first quarter of the year in which the construction is to take place. Costs for each component of the project are approximately engineering/design: 10%, construction: 65%, and closeout: 25%. The project is currently in the evaluation stage.

b. See attachment U-21490-AG-CE-0293-Griffin_ATT_1 for the projects with in-service dates of 2021 and 2023 along with the actual capital expenditures. The remaining spend in the program is for projects that were put into service in other years. Most projects have expenditures in more than one calendar year.

Witness: MICHAEL P. GRIFFIN
Date: April 3, 2024

U-21490-AG-CE-293-Griffin_ATT_1

Prj Definition	Project Name	2021 ($000s)	2023 ($000s)	In Service
GL-02059	FDM-4060 Vector Int PLD Inst	1,021	2,733	2023
GL-02070	STC-2700 Squirrel Rd VS PLD Inst	-	5,192	2023
GL-02652	STC-2700 Dixie Wtrfrd CG PLD	3,162	68	2021
GL-03026	KZO-1200A CE-ANR Stag Lk VS PLD Inst	9	3,868	2023

MICHIGAN PUBLIC SERVICE COMMISSION — Case No. U-21490
Consumers Energy Company — WP-MPG-8
Actual & Projected Gas Transmission Capital Expenditures — Page 1 of 1
TED-I Pressure Limiting Devices (PLDs) Project Details

Project ID	Project Description	Location	2022 Actual	2023 Projection	2024 Projection	2025 Projection	9 ME 9/30/2024	Test Year 12 ME 9/30/25
GL-01653	SAG-500 Grand Blanc Interchange PLD	City: Grand Blanc / Genessee County	31,666	0				
GL-01654	FDM-100B Ovid VS PLD	City: Ovid / Clinton County	2,679,166	(576)				
GL-01656	FDM Line 1100 Laingsburg PLD Installation	City: Lainsburg / Shiawasee County		0	3,148,517		3,148,517	
GL-01661	OVS-1300 Plainwell VS PLD Inst	City: Plainwell / Allegan County	-13,552	0				
GL-02052	MAR-2400A Gillow VS PLD Inst	City: Merritt / Missaukee County	-168,532	0				
GL-02056	FDM-1200A HH VS PLD Inst	City: Lake City / Missaukee County	28,433	0				
GL-02059	FDM-4060 Vector Int PLD Inst	City: Horton / Jackson County	343,296	2,697,465				
GL-02060	FDM-4070 Vector Int PLD Inst	Hartland Township / Livingston County	2,898,803	(73,773)				
GL-02061	MAR-2400 MRCS PLD Inst	Ray Township / Macomb County	21,663	(23,280)				
GL-02062	SAG-250 Zilwke CG PLD Inst	Marion Township / Clare County	-234,083	0				
GL-02065	STC-1020 SLyon WtmrLk CG PLD Inst	City: Saginaw / Saginaw County	36,792	0				
GL-02068	STC-2700 Dutton Rd VS 26in PLD Inst	City: South Lyon / Oakland County	38,112	0				
GL-02070	STC-2700 Squirrel Rd VS PLD Inst	City: Rochester Hills / Oakland County	48,399	5,116,272				
GL-02075	STC-600 Clrkstn Int PLD Inst	City: Lake Orion / Oakland County	0	3,997				
GL-02394	SAG-300 ZilJnctn PLD's Inst	City: Clarkston / Oakland County	-195,538	0				
GL-02411	KZO-1800 Plainwell VS PLD Inst	City: Saginaw / Saginaw County	0	106,702				
GL-02579	SAG-250 GL Chipwa Int PLD Inst	City: Plainwell / Allegan County	0	60,784				
GL-02651	NVL-1400 Clarkston Jct PLD	City: Holly / Oakland County	-27,193	(46,800)				
GL-02652	STC-2700 Dixie Wtrfrd CG PLD	City: Mt. Pleasant / Isabella County	6,422	67,899				
GL-02854	OVS-1100 Woodbury CG PLD Inst	City: Lake Odessa / Ionia County	3,367,281	91,834				
GL-02997	STC-2070 Dutton Rd VS PLD Inst	City: Rochester Hills / Oakland County	2,982,422	44,904				
GL-02998	STC-1500 Rochester VS PLD Inst	City: Rochester Hills / Oakland County	2,800,905	81,019				
GL-03026	KZO-1200A CE-ANR Stag Lk VS PLD Inst	City: White Pigeon / St. Joseph County	740,686	4,109,033				
	TOTAL EXPENDITURE		**15,385,151**	**12,235,477**	**3,148,517**	**0**	**3,148,517**	**0**

Question:

152. Refer to page 29 of Mr. Joyce's direct testimony and WP-TKJ-5 on the Overisel compression station. For each of the projects or group of projects in WP-TKJ-5 of $3 million or greater for 2024 and 2025, please provide the following information:
a. The cost of the project by year from inception to completion.
b. Explain what is the problem and why is the project is necessary?
c. Explain what alternatives were evaluated and what financial benefits will result from completion of the project.
d. The phases of project development for each project with timeline and related cost and the phase that the project is currently in.

Response:

<u>Unitized Cooling (GC-00759)</u>:

a. 2019: $0.29M
2020: $0.05M
2021: $2.30M
2022: $10.15M
2023: $26.80M
2024: $11.80
2025: $0.3M

b. This project provides for a reduction in random outage rate (ROR) risk of the facility due to aging components at the end of useful life, ROR contributions due to equipment failures have been intermittent over the past ten years at Overisel, in some years resulting in a station overall ROR impact of 25%. Improvement to gas resilience for the Overisel Compressor and Storage area, by reduction in single point failures within the infrastructure of Overisel Compressor Station, including the addition of the suction and discharge bypass will allow the plant to take gas from ANR during maintenance or projects that would otherwise stop the flow.

c. Alternative options for this project are 1.) Modify two of four compressor installations, with separate coolers and upgraded piping. Intent is to allow parallel operation with one stage and two stage operation. 2.) Replace both the interstage and second stage coolers only. 3.) Modify the gas storage fields to reduce the volume and frequency of liquids intrusions on the compressor station. 4.) Do nothing.

d. This project is currently in Procurement and Construction in 2024 and Closeout in 2025.

<u>Station Controls Upgrade (GC-00124)</u>:

a. 2022: $0.16M
2023: $0.66M
2024: $1.62M
2025: $1.63M

b. This project replaces obsolete equipment associated with the SCADA network which cannot be directly replaced as there is no available inventory to procure. It provides clear separation of GAS SCADA network and Station Control Network will establish clear boundaries for Cyber Security Controls and updates as required by API 1164. Additionally, allows for update of system control design philosophy with latest industry standards to eliminate single point failures, and incorporation of system design best practices and lessons learned from internal company problem solving.

c. The project offers an alternative to continue operating with the current configuration and risk reliability and deliverability impacts upon failure of obsolete equipment. Completing the proposed upgrade project will bring improved reliability, better monitoring and automation, standardization of equipment, and reduced maintenance needs, ultimately ensuring more reliable, safe and efficient operation to the site.

d. This project is currently in Engineering and Procurement in 2024, Construction in 2025, and Closeout in 2026.

Lube Oil Extractor (GC-00837):

a. 2024: $0.75M
2025: $5.89M
2026: $2.6M

b. Following the completion of the Unitized Cooling Project, the only form of post compression lube oil extraction (LOE) from natural gas being sent to the fields / mainline will be two low point piping siphons, which is not viewed as a sufficient means of preventing sending compressor lubrication oil out beyond the boundaries of the station and does not reflect best practice standards for LOE at other compressor stations in the fleet.

c. An alternative to the proposed project would be to operate the system without the installation of the proposed lube extractor and rely solely on transmission network pigging maintenance and city gate filtration to protect distribution systems from oil carryover and potential service disruption to customers. This alternate option risk is not desirable and permits ease of handling/disposal at the source location of the compressor station as well as reduced cost of fluid handling.

d. This project is currently in the Initiation, Planning and Engineering in 2024, Procurement and Construction in 2025, and Closeout in 2026.

Engine Exhaust Emissions Control (GC-00790):

a. 2023: $0.083M
2024: $8.08M
2025: $3.77M
2026: $3.6M

b. The Environmental Protection Agency (EPA) plans to implement new emission standards, known as the "Good Neighbor" plan, targeting industrial sources in 23 states to reduce ground-level ozone pollution starting in 2026. To comply with these regulations and meet EPA and EGLE requirements, compression units must reduce NOx emissions to 3g/Bhp or lower. Achieving Low Emission Combustion (LEC) necessitates adding Pre-combustion chambers (PCC) and modifying or replacing the existing turbos to achieve airflow.

c. Alternative options; 1.) Selective Catalysts Reduction (SCR), or 2.) three-way oxidation catalyst installed on the exhaust system to reduce NOx levels. These alternatives would 1.) increase operating cost through urea consumption of one to five gallons per hour per unit and increase system wear due to the corrosive properties of urea. 2.) the existing units operate too lean for the catalyst to function property and would require combustion in a narrower range to be effective. The recommended solution will achieve emissions requirement and will improve engine reliability, emissions, and reduce fuel consumption.

d. This project is currently in the Initiation and Planning in 2024; Engineering, Procurement, and Construction in 2025; and Closeout in 2026.

Witness: Timothy K. Joyce
Date: April 4, 2024

Site	Title	2023 7+5 Fcst	2024	2025	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	Projected Bridge Year 21 Mos Ending 9/30/2024	Projected Test Year 12 Mos Ending 9/30/2025	Projected 9 Mos ending in 9/30/23	Projected 12 Mos. Ending 9/30/24	Projected 12 Mos Ending 9/30/2024	Projected 33 Mos ending 9/30/24
Site	Title	2023 7+5 Fcst	2024	2025								
Overisel	(13264) Salem Scrubber Replacement	0	0	50	0	0	0	40	0	0	40	40
Jackson	(13247) Disposal Well Monitoring System	0	0	110	0	0	0	87	0	0	87	87
Overisel	(11290) OVS - Salem Scrubber Brine Tanks Replacement	0	3,328	50	0	2,644	2,644	724	0	2,644	724	3,368
Overisel	(5989) Storage Small Valves and Instrumentation	1	0	0	1	0	1	0	0	1	0	1
Overisel	(6550) Storage Tools and Instrumentation	103	0	0	103	0	103	0	0	103	0	103
Overisel	OVS-O142 Secondary Cont Repl	28	0	0	28	0	28	0	20	7	0	28
Overisel	OVS-O142 Pump House Bldng Repl	2	0	0	2	0	2	0	2	0	0	2
Overisel	OVS - Salem Tank Hi Level Alarm Repl	0	0	0	0	0	0	0	0	0	0	0
Overisel	OVS- Salem Scrubber Brine Tanks Replacement	326	0	0	326	0	326	0	218	108	0	326
Overisel	OVS- Salem Goodman Disposal Well Tank Replacement	1,218	0	0	1,218	0	1,218	0	1,060	158	0	1,218
	TOTAL OVERISEL	1,679	3,328	210	1,679	2,644	4,323	850	1,300	3,022	850	5,173

Question:

150. Refer to page 28 of Mr. Joyce's direct testimony and WP-TKJ-5 on the Muskegon River compression station. For each of the projects or group of projects in WP-TKJ-5 of $3 million or greater for 2024 and 2025, please provide the following information:
a. The cost of the project by year from inception to completion.
b. Explain what is the problem and why is the project is necessary?
c. Explain what alternatives were evaluated and what financial benefits will result from completion of the project.
d. The phases of project development (needs assessment, project scoping, conceptual design, engineering design, contract bidding, construction, completed, etc.) for each project with timeline and related cost and the phase that the project is currently in.

Response:

<u>**Unit Overhaul (GC-00842)**</u>:

a. 2024: $1.7M
   2025: $7.0M

b. Muskegon River Unit H-10 requires a zero hour rebuild due to normal degradation and requires mechanical repair. The rebuild will restore all major components on the power and compressor side to like-new condition within OEM tolerance. The project includes complete disassembly, refurbishment of major components, replacement of worn parts, and reassembly followed by startup and testing.

c. The alternative options would be replacing the existing engine and compressor unit with a new reciprocating unit. This would be a large capital expenditure, introduce a new model to the site which would require additional parts inventory, and be a large disruption to the current operation. Rebuilding the existing unit will return the unit to like-new condition, improve unit reliability and increase unit efficiency.

d. This project is currently in the Initiation and Planning in 2024, Engineering, Procurement and Construction in 2025, and Closeout in 2026.

<u>**Engine Exhaust Emissions Control**</u>:

a. 2024: $2.5M
   2025: $12.5M
   2026: $10.0M

b. The Environmental Protection Agency (EPA) plans to implement new emission standards, known as the "Good Neighbor" plan, targeting industrial sources in 23 states to reduce ground-level ozone pollution starting in 2026. To comply with these regulations and meet EPA and EGLE requirements, compression units must reduce NOx emissions to 3g/Bhp or lower. Achieving Low Emission Combustion (LEC) necessitates adding Pre-combustion chambers (PCC) and modifying or replacing the existing turbos to achieve airflow.

c. Alternative options; 1.) Selective Catalysts Reduction (SCR), or 2.) three-way oxidation catalyst installed on the exhaust system to reduce NOx levels. These alternatives would 1.) increase operating cost through urea consumption of one to five gallons per hour per unit and increase system wear due to the corrosive properties of urea. 2.) the existing units operate too lean for the catalyst to function property and would require combustion in a narrower range to be effective. The recommended solution will achieve emissions requirement and will improve engine emissions and reduce fuel consumption.

d. This project is currently in the Initiation and Planning in 2024, Engineering, Procurement and Construction in 2025, and Closeout in 2026.

<u>Closed-Loop Cooling (GC-00630)</u>:

a. 2022: $0.12M
2023: $0.72M
2024: $5.77M
2025: $1.62M

b. Muskegon River Compressor Station was issued a renewed National Pollutant Discharge Elimination System (NPDES) Certification of Coverage, COC No. MIG250103 on November 17, 2022. The renewed COC subjects the facility to a daily maximum temperature limit of 91 degrees Fahrenheit which will become effective January 1, 2026. Muskegon River Compressor Station cannot meet this temperature limit under current operating conditions. By eliminating noncontact cooling water use prior to January 1, 2026, the site will no longer discharge wastewater and the NPDES permit can be terminated.

c. The alternative option would be to continue operating with river water cooling. Utilizing this alternative would require significant repair to the current discharge line, supply line and makeup tank and require system upgrades to meet the NPDES discharge temperature limits. Eliminating river water cooling results in a significant system upgrade savings, reduces operating expense of equipment (pumps, filters, flow meter, etc.) and eliminates the environmental concerns of utilizing open discharge river water.

d. This project is currently in Engineering, Procurement and Construction in 2024, and Construction, Closeout in 2025.

Witness: Timothy K. Joyce
Date: April 4, 2024

Compression Capital Detail (2023-2025)
For Gas Rate Case - December 2023
($000)

						Projected Bridge Year	Projected Test Year	Projected			
Title	**2023 7+5 Fcst**	**2024**	**2025**	**12 Mos Ending 12/31/2023**	**9 Mos Ending 9/30/2024**	**21 Mos Ending 9/30/2024**	**12 Mos Ending 9/30/2025**	**9 Mos ending in 9/30/23**	**12 Mos. Ending 9/30/24**	**12 Mos Ending 9/30/2025**	**33 Mos ending 9/30/25**
(11382) MRC - P2 TEG Charcoal Filter Install	1,100	30	0	1,100	21	1,122	9	1,001	121	9	1,130
(11383) MRC - P2 Air Comp Replace	526	1,800	0	526	1,289	1,815	511	417	1,398	511	2,326
(12187) MRC - Lubricator Sys Repl Prog	0	90	0	0	64	64	26	0	64	26	90
(13119) MRC - Parking Lot Asphalt Rebuild	0	400	0	0	286	286	114	0	286	114	400
(13813) MRC - P2 Nox Emissions Install	0	2,500	12,538	0	1,790	1,790	9,688	0	1,790	9,688	11,478
(13814) MRC - Turbine Catalyst Install	106	1,500	0	106	1,074	1,180	426	0	1,180	426	1,606
(13815) MRC - P2 Det Installation	54	54	0	54	39	93	15	0	93	15	108
(13816) MRC - Cond Dump Heat Trace Intall	0	0	100	0	0	0	72	0	0	72	72
(6349) MRC - Station Control Panel Install	0	0	258	0	0	0	185	0	0	185	185
(6435) MRC-Clark Unit H-10- Unit Rbld	0	1,700	7,002	0	1,217	1,217	5,497	0	1,217	5,497	6,714
(6444) MRC - Vlv 119, 120, 219 Replacement	0	244	400	0	175	175	356	0	175	356	531
(9191) MRC Plant 2 Closed Loop Cooling System	1,070	5,772	1,618	1,070	4,133	5,203	2,797	552	4,651	2,797	8,000
(12184) MRC - H12 Lubricator Sys Repl	0	0	90	0	0	0	64	0	0	64	64
(12188) MRC - P2 Jet Removal	0	0	0	0	0	0	0	0	0	0	0
(12191) MRC - H11 Lubricator Sys Repl	90	0	0	90	0	90	0	0	90	0	90
(11232) MRC P2 Lean TEG Sys Repl	250	0	0	250	0	250	0	250	0	0	250
(7074) - MRC Jet Replacement	317	0	0	317	0	317	0	291	25	0	317
MRC-Clark HBA-11 EngCompr Rbld	34	0	0	34	0	34	0	34	0	0	34
MRC-Clark HBA-9 EngCompr Rbld	14	0	0	14	0	14	0	14	0	0	14
MRC-Compression Capital Tools	0	0	0	0	0	0	0	6	(6)	0	0
MRC-Plnt 2 Firegate Vlvs Repl	1,080	0	0	1,080	0	1,080	0	1,046	34	0	1,080
MRC-Plt 3 FireGate Vlv(s) Rmvl	13	0	0	13	0	13	0	13	0	0	13
TOTAL MUSKEGON RIVER	4,654	14,090	22,006	4,654	10,090	14,744	19,759	3,624	11,119	19,759	34,502

Question:

151. Refer to page 29 of Mr. Joyce's direct testimony and WP-TKJ-5 on the Northville compression station. For each of the projects or group of projects in WP-TKJ-5 of $3 million or greater for 2024 and 2025, please provide the following information:
a. The cost of the project by year from inception to completion.
b. Explain what is the problem and why is the project is necessary?
c. Explain what alternatives were evaluated and what financial benefits will result from completion of the project.
d. The phases of project development for each project with timeline and related cost and the phase that the project is currently in.

Response:

Engine Controls Upgrade (GC-00775):

a. 2023: $0.01M
2024: $1.72M
2025: $5.15M

b. The Unit 1 and Unit 2 control panels are outdated, lacking essential features such as engine performance calculations and trending capabilities. This poses reliability and safety risks as compressors may operate beyond safe parameters. Troubleshooting and maintenance are hindered due to obsolete electrical components and lack of vendor support, resulting in extended downtime. The project aims to replace the panels with new ones equipped with the latest technology, including AB PLCs, and upgrade auxiliary components for standardized unit controls.

c. The project offers two alternative options: continue operating with the current configuration and risk reliability and deliverability impacts upon failure or invest in new compressor units for better performance. Completing the proposed upgrade project will bring improved reliability, better monitoring, standardization of equipment, and reduced maintenance needs, ultimately ensuring more reliable, safe and efficient operation to the site.

d. This project is currently in the Engineering and Procurement in 2024, Engineering, Construction in 2025, and final Closeout in 2026.

Engine Exhaust Emissions Control:

a. 2024: $2.0M
2025: $6.1M
2026: $5.5M
2027: $1.5M

b. The Environmental Protection Agency (EPA) plans to implement new emission standards, known as the "Good Neighbor" plan, targeting industrial sources in 23 states to reduce ground-level ozone pollution starting in 2026. To comply with these regulations and meet EPA and EGLE requirements, compression units must reduce NOx emissions to 3g/Bhp or lower. Achieving Low Emission Combustion (LEC) necessitates adding Pre-combustion chambers (PCC) and modifying or replacing the existing turbos to achieve airflow.

c. Alternative options; 1.) Selective Catalysts Reduction (SCR), or 2.) three-way oxidation catalyst installed on the exhaust system to reduce NOx levels. These alternatives would 1.) increase operating cost through urea consumption of one to five gallons per hour per unit and increase system wear due to the corrosive properties of urea. 2.) the existing units operate too lean for the catalyst to function property and would require combustion in a narrower range to be effective. The recommended solution will achieve emissions requirement and will improve engine reliability, emissions, and reduce fuel consumption.

d. This project is currently in the Initiation and Planning in 2024, Engineering, Procurement and Construction in 2025/26, and Closeout in 2027.

Witness: Timothy K. Joyce
Date: April 4, 2024

Compression Capital Detail (2023-2025)
For Gas Rate Case - December 2023
($000)

Title	2023 7+5 Fcst	2024	2025	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	Projected Bridge Year 21 Mos Ending 9/30/2024	Projected Test Year 12 Mos Ending 9/30/2025	Projected 9 Mos ending in 9/30/23	Projected 12 Mos. Ending 9/30/24	Projected 12 Mos Ending 9/30/2025	Projected 33 Mos ending 9/30/25
Title	**2023 7+5 Fcst**	**2024**	**2025**								
(11235) NVL - Elec Sys Upgrade	637	2,390	49	637	1,711	2,348	714	531	1,817	714	3,062
(11397) NVL - Resiliency Assessment Projects	0	0	0	0	0	0	0	0	0	0	0
(13148) NVL - Relief Vlv Replacements	75	100	75	75	72	147	82	0	147	82	229
(13817) NVL-Plt1 U1-4 NOx Red	0	2,000	6,100	0	1,432	1,432	4,936	0	1,432	4,936	6,368
(13818) NVL-Plt1 JW Cooler Repl	0	650	1,250	0	465	465	1,080	0	465	1,080	1,545
(13819) NVL - PLT1 Comp Air Sys Upgrade	0	0	250	0	0	0	179	0	0	179	179
(6445) NVL-Air Comp #2 Repl	0	0	177	0	0	0	127	0	0	127	127
(6455) NVL-Unit 1 and 2 Eng Cntrl Upgd	969	1,721	5,149	969	1,232	2,202	4,176	97	2,105	4,176	6,378
(8115) NVL - Firegate Valve Replacements	1,841	50	0	1,841	36	1,877	14	1,762	114	14	1,891
NVL-Line 1020 Vlv 604 Repl	3	0	0	3	0	3	0	3	0	0	3
NVL-Back-up Gen Repl	55	0	0	55	0	55	0	55	0	0	55
TOTAL NORTHVILLE	3,580	6,911	13,051	3,580	4,949	8,528	11,307	2,448	6,080	11,307	19,836

Question:

153. Refer to page 30 of Mr. Joyce's direct testimony and WP-TKJ-5 on the St. Clair compression station. For each of the projects or group of projects in WP-TKJ-5 of $3 million or greater for 2024 and 2025, please provide the following information:
a. The cost of the project by year from inception to completion.
b. Explain what is the problem and why is the project is necessary?
c. Explain what alternatives were evaluated and what financial benefits will result from completion of the project.
d. The phases of project development for each project with timeline and related cost and the phase that the project is currently in.

Response:

<u>Turbine Gas Cooler (GC-00651)</u>:

a. 2023: $0.19M
2024: $2.3M
2025: $2.3M

b. St. Clair Plant 1 turbine aftercoolers require replacement as the existing units are beyond the end of their useful service life. Components of the system have failed over the last several years and have required emergent replacement with direct impact on station deliverability. The project will increase deliverability at higher fluid differentials and eliminate excessive pressure drop through the existing cooler structure and reduce deliverability risk associated with equipment failure.

c. The alternative option is to continue operating with the current gas coolers. These units operate at low efficiency due to general system corrosion and damaged or bent heat exchanger fins which limits cooling air. Continued operation will increase break/fix activity impacting station deliverability and throughput and results in a higher operating cost due to inefficiency and emergent repairs.

d. This project is currently in Engineering in 2024; Procurement, Construction, and In-Service in 2025; and Closeout in 2026.

<u>Blowdown Vent Stack (GC-00785)</u>:

a. 2024: $2.7M
2025: $3.0M
2026: $0.5M

b. During the routine annual Plant 4 fire gate activation, Unit 1-2 was running and shut down on a high T5 alarm from ingesting gas into the unit air intake. During the investigation, dispersion modeling indicated the blow down stack design and stack height resulted in gas discharging at an insufficient elevation. The blown down vent stacks will be redesigned to discharge at a higher elevation providing adequate dispersion of the gas released during fire gate activation.

c. The alternative options to vent stack design are 1) relocating the Plant 1 Gas Turbines or 2) make current engineering interlock controls permanent mode of operation. Turbine relocation is cost prohibitive and redesign of the current vent stacks is the most economical option. Redesigning the vent stacks to eliminate/redesign the rain cap and the increase in discharge height to eliminate the gas dispersion risk associated with the Plant 1 Gas Turbine air intakes and remove the deliverability constraint currently in place during a fire-gate of Plant 3 or 4 to initiate an emergency shutdown of the Plant 1 Turbines.

d. This project is currently in the Initiation and Planning in 2024; Engineering and Procurement in 2025; Construction, In-Service, and Closeout in 2026.

Witness: Timothy K. Joyce
Date: April 4, 2024

Compression Capital Detail (2023-2025)
For Gas Rate Case - December 2023
($000)

Title	2023 7+5 Fcst	2024	2025	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	Projected Bridge Year 21 Mos Ending 9/30/2024	Projected Test Year 12 Mos Ending 9/30/2025	Projected 9 Mos ending in 9/30/23	Projected 12 Mos. Ending 9/30/24	Projected 12 Mos Ending 9/30/2025	Projected 33 Mos ending 9/30/25
Title	**2023 7+5 Fcst**	**2024**	**2025**								
(12112) STC - P3 Engine Controller Replacement	1,310	30	0	1,310	21	1,331	9	1,282	50	9	1,340
(12142) STC - Resiliency Assessment Projects	0	249	149	0	178	178	177	0	178	177	355
(13165) STC - P1 FG Piping and Filter Install	300	250	0	300	179	479	71	0	479	71	550
(13166) STC - P3 Lube Oil Filter Repl	0	400	0	0	286	286	114	0	286	114	400
(13808) GC-00785 STC - Blowdown Vent Stack Repl	200	2,736	3,000	200	1,959	2,159	2,925	0	2,159	2,925	5,084
(13809) STC - P4 Superheater Repl	0	250	1,100	0	179	179	859	0	179	859	1,038
(13810) STC - P1 Unit RV Replacements	0	60	250	0	43	43	196	0	43	196	239
(13811) GC-00807 - STC - P3 Glycol Tank Repl	320	50	0	320	36	356	14	0	356	14	370
(6520) GC-00651 STC - P1 Gas Cooler Replacement	861	2,300	2,300	861	1,647	2,508	2,300	470	2,038	2,300	4,808
(12140) STC - U1-1 Exhaust Silencer Repl and 1-2 Comp Rebuild	948			948	0	948	0	0	948	0	948
STC-1060 Vlv GV805 Repl	6	0	0	6	0	6	0	6	0	0	6
STC-Press Reducing Vlv(s) Repl	11	0	0	11	0	11	0	11	0	0	11
STC-P3 Suct Filt Sep Inst	1	0	0	1	0	1	0	1	0	0	1
STC-H2O Transducer Inst	1	0	0	1	0	1	0	1	0	0	1
STC Engine Crankcase Press Transmitter	0	0	0	0	0	0	0	0	0	0	0
STC-Station Upgrade	1	0	0	1	0	1	0	1	0	0	1
STC-1-2 Exhaust Silencer Repl	2	0	0	2	0	2	0	2	0	0	2
STC-Plt3 FG Mods AFC	(3)	0	0	(3)	0	(3)	0	(3)	0	0	(3)
STC-Plt3 Wtr Cool FanGbox Repl	444	0	0	444	0	444	0	216	228	0	444
STC-Heater HMI Repl	15	0	0	15	0	15	0	8	7	0	15
STC-Solar T4500 ECP Upgrd	(12)	0	0	(12)	0	(12)	0	(12)	0	0	(12)
ST CLAIR TOTAL	4,403	6,324	6,798	4,403	4,529	8,932	6,664	1,981	6,951	6,664	15,596

U21490-AG-CE-0314
Page **1** of **2**

Question:

156. Refer to pages 31-32 of Mr. Joyce's direct testimony and WP-TKJ-6 on the Riverside storage field retirement project. Please provide the following information
a. The cost of the project by year from inception to completion.
b. Explain what alternatives were evaluated, and what financial benefits will result from completion of the project. Provide a copy of the cost/benefit analysis performed in Excel with formulas intact and all assumptions explained.
c. The phases of project development with timeline and related cost and the phase that the project is currently in.
d. Explain what has changed since the Company proposed this project in Case No. U-21308. Provide any updates to the responses to the Attorney General's discovery requests in that case.
e. Provide the new threshold for Finance Committee approval and when the threshold was changed.
f. Provide evidence that the Company CEO has approved the total cost of this project, or the cost approved to date.

Response:

a. Please reference attachment U21490-AG-CE_Joyce_ATT_2 for the cost of the project by year from inception to completion.

b. Please reference attachment U21490-AG-CE_Joyce_ATT_1 for a 2021 project summary of the Riverside Retirement Project which includes the analysis and evaluation of alternatives performed by the Company with related costs and recommendations.

c. Please reference attachment U21490-AG-CE_Joyce_ATT_2 for the phases of project development with timeline and related cost and the phase that the project is currently in.

d. Please reference the response to U21490-ST-CE-0079, U21490-ST-CE-0080, and U21490-ST-CE-0081 for updated status on the Riverside Storage Field project.

   U21308-AG-CE-0434 – No additional updates beyond what is included in this question.
   U21308-AG-CE-0562—No updates
   U21308-AG-CE-0563—No updates

e. Updated Finance Committee approval policy, November 2022.

Topic	Approval (mils)	Approval (mils)	Board or Committee Review
Capital Expenditures and Leases (including acquisition) • Projects/Leases Not Approved in Budget • Real Property and Property Interests	>$425	Finance >$125	As needed

f. The projected Riverside Retirement project expenditures included in Exhibit A-12 (TKJ-5) Schedule B-5.8 were approved by the Senior Management Team, including the CEO, on October 10, 2023, during the annual budget review meeting.

Witness: Timothy K. Joyce
Date: April 3, 2024

Storage Capital Detail (2023-2025)
For Gas Rate Case - December 2023
($000)

							Projected Bridge Year	Projected Test Year	Projected			
Site	Title	2023 7+5 Fcst	2024	2025	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	21 Mos Ending 9/30/2024	12 Mos Ending 9/30/2025	9 Mos ending in 9/30/23	12 Mos. Ending 9/30/24	12 Mos Ending 9/30/2024	33 Mos ending 9/30/24
Riverside	(12355) Riverside Storage - Distribution Facilities Installation	0	40,045	23,930	0	31,817	31,817	27,241	0	31,817	27,241	59,058
Riverside	(12354) Riverside Regulation (M&R) Equipment	0	1,889	11,878	0	1,501	1,501	9,826	0	1,501	9,826	11,327
Riverside	MAR-Rvrsd HP Dist Feed from 2400 to RS	6,556	0	0	6,556	0	6,556	0	6,171	385	0	6,556
Riverside	MAR-Rvrsd MP Dist Forward & Falmouth CG	5,639	0	0	5,639	0	5,639	0	5,639	0	0	5,639
Riverside	MAR-Rvrsd New CG near Gas Supply Locat.	25	0	0	25	0	25	0	25	0	0	25
Riverside	MAR-Rvrsd Install RS near SC&M-66	42	0	0	42	0	42	0	42	0	0	42
Riverside	MAR-RVD L2400 Dual Tap ML Vlv	4	0	0	4	0	4	0	4	0	0	4
Riverside	MAR-Rvrsd P&A Wells	(151)	0	0	(151)	0	(151)	0	21	(172)	0	(151)
	TOTAL RIVERSIDE FIELD RETIREMENT	12,114	41,934	35,808	12,114	33,318	45,432	37,067	11,901	33,532	37,067	82,499

U21490-ST-CE-0079
Page **1** of **1**

Question:

56. Referring to page 31, lines 5-6 of the Witness's direct testimony; has the analysis concluded and, if so, what was the determination? If not, when does the Company anticipate the analysis to be concluded?

Response:

The analysis has concluded, and the Company is actively pursuing the option of selling the field to a third party.

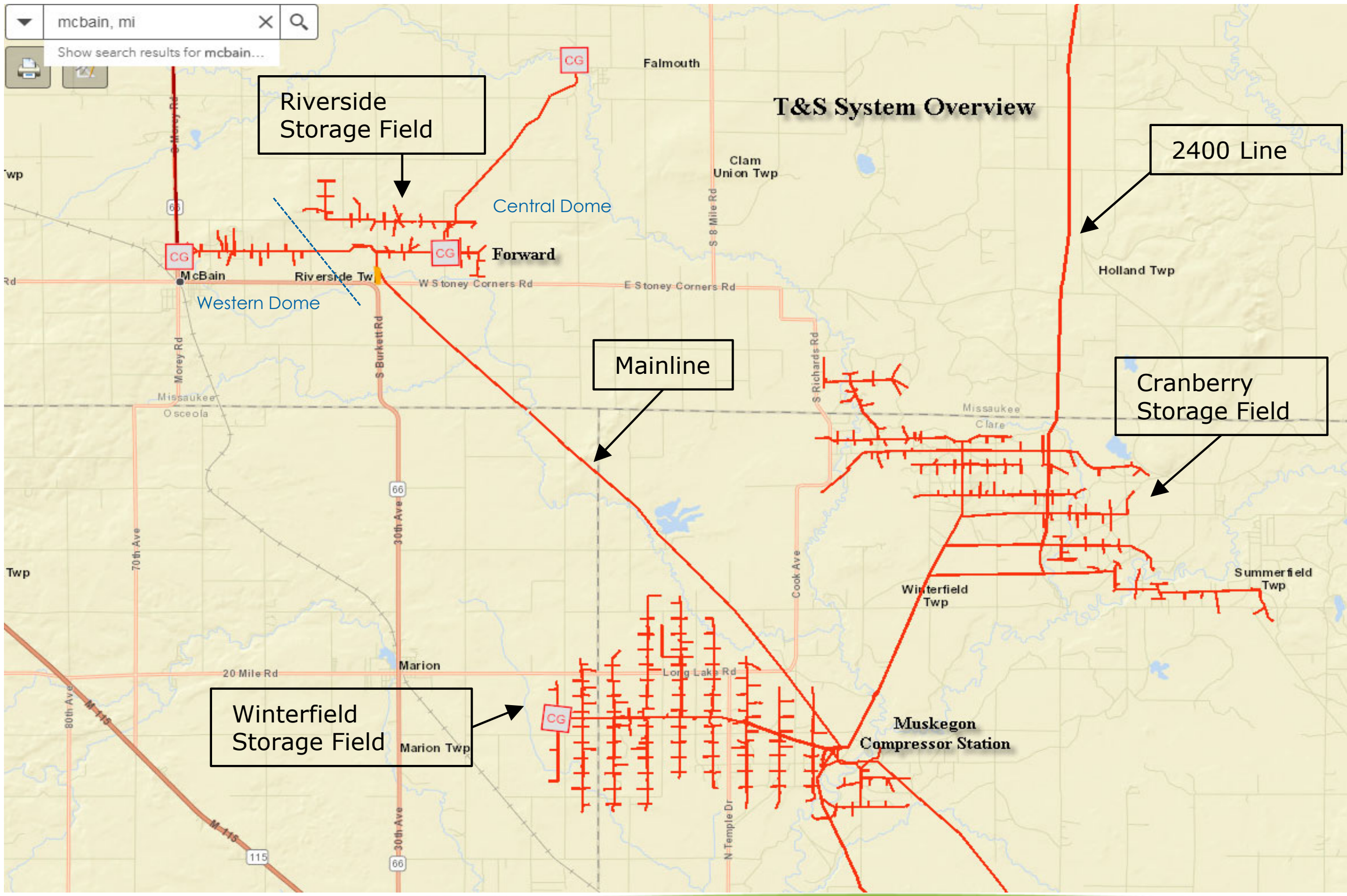
Witness: Timothy K. Joyce
Date: February 23, 2024

THE REST OF THE EXHIBIT CONSIST OF A 12 PRESENTATION
RIVERSIDE PROGRAM SUMMARY (MAY 2021)

Riverside Program Summary (May 2021)

Consumers Energy
Count on Us®

Background – Current State May 2021



Riverside Storage Field
- Central Dome - 67 wells
  - ~6.5 bcf (~1.1 bcf Working Gas)
- Western Dome - 30 wells
  - ~2.5 bcf (~0.4 bcf Working Gas)
- Cyclic Capacity ~0.3 bcf (Due to de-rates and limits associated with city gates)

City Gates
- McBain City Gate – 2700 Customers
- Forward City Gate – 65 Customers
- Falmouth City Gate – 100 Customers

Distribution
- Only way to feed customers is through Riverside Mainline and Gas Storage Laterals

Current Condition
- 3 Laterals de-rated due to integrity concerns
  - Lat 81 – 100psi MAOP only feeds FGUs
- Riverside Mainline – Pre-1970 ERW with Selective Seam Weld Corrosion (SSWC), 48% has long seam on bottom half of pipe
- McBain CG will need to be rebuilt regardless to supply customer demand
- Wells would have to be logged/Rehabbed under another program

Summary
- Various projects needed for integrity, compliance and deliverability reasons for a field with a current cyclic capacity of 0.3 bcf.

Problem Statement

- The Riverside gas storage field has low working gas capacity, high well count, and native H2S as observed from Riverside wells occurring high on the SIMP risk list.
- The Riverside gas storage field is connected directly to three city gates which limits the withdrawal volume from the field and the ability to take outages for maintenance or capital projects and ability to increase capacity at McBain city gate.
- Due to integrity issues the risk of equipment failures is increasing with time as seen through increased digs on Riverside Mainline and lateral 80W leak.
- Due to integrity issues and class location changes Lateral 81 W&E are de-rated to only provide gas to FGU and would otherwise be abandon.

Strategic Objectives

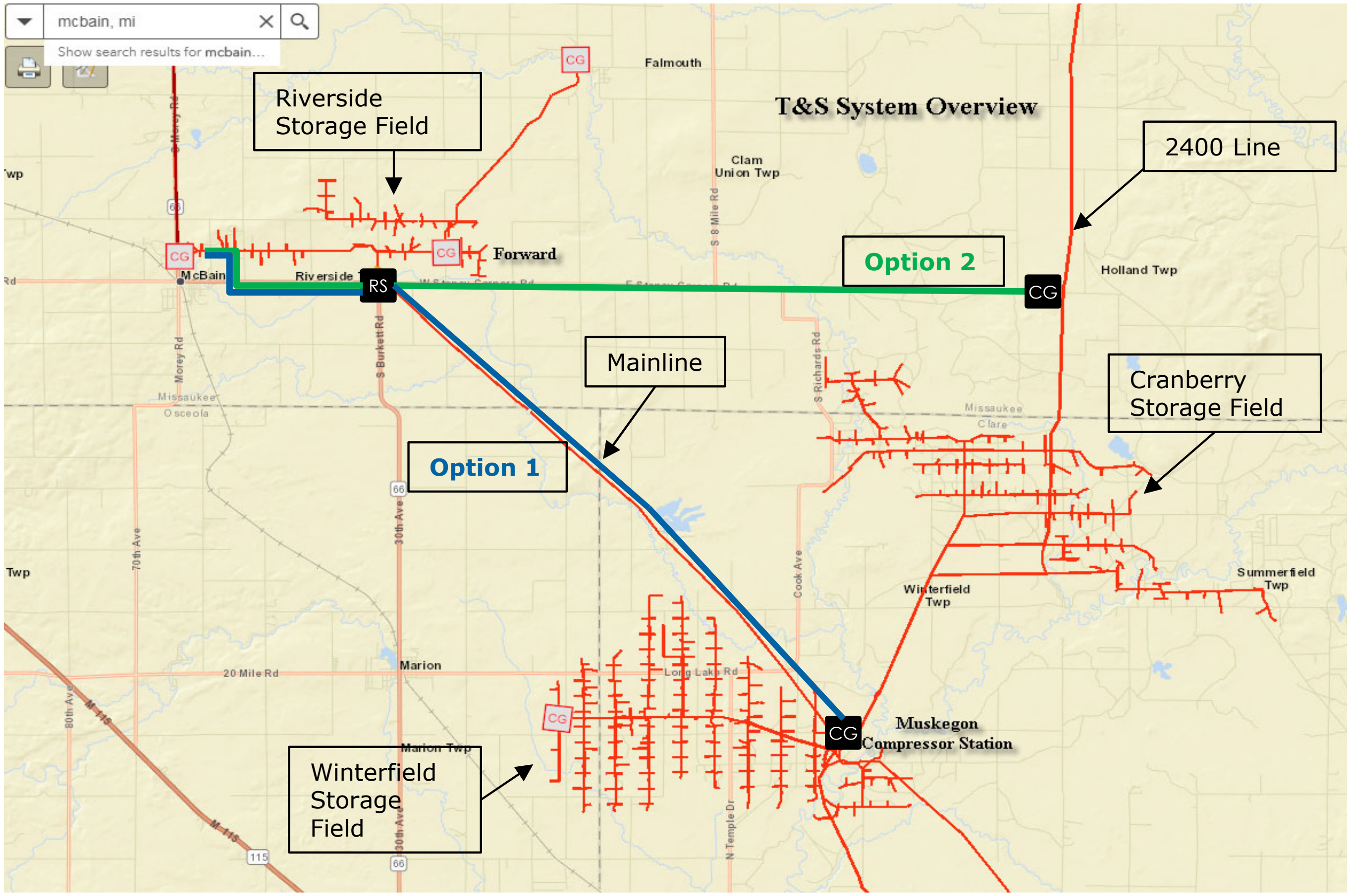
- **Safe** – Retire or rehabilitate assets with integrity concerns resulting in risk reduction in the SIMP and TIMP Models.
- **Reliable** - Improve resiliency and reliability to customers connected to McBain, Forward and Falmouth City Gates and provide reliable gas supply for Riverside area. Currently the customers are being supplied gas through the storage system which has been problematic due to current integrity concerns, de-rates and outage coordination.
- **Affordable** – Meet GMS needs for gas supply to continue to provide affordable gas in the Riverside area while still maintaining reliable gas supply.
- **Clean** – Reduce methane emissions (leaks, fugitive emissions) from Riverside wells and related facilities

Alternatives Considered

Retire Western Dome		Keep Western Dome		Status Quo (Keep Western Dome)
Option 1	Option 2	Option 4	Option 5	Option 6
• Install Distribution main from near Muskegon River Compressor Station • Install new City Gate and Reg. Station • Retire storage assets; wells, laterals, gas conditioning, mainline • Retire 3 City Gates	• Install Distribution main from Line 2400 • Install new City Gate and Reg. Station • Retire storage assets; wells, laterals, gas conditioning, mainline • Retire 3 City Gates	• Replace Riverside Mainline, Laterals, New Well • Install Distribution main, city gate and reg station • Retire 3 City Gates • Storage and Distribution assets connected but improvement from current state.	• Add Distribution main parallel to Riverside Mainline • Replace Riverside Mainline, Laterals, New Well • Install Distribution main, city gate and reg station • Retire 3 City Gates • Separate Distribution and Storage assets	• Re-coat Riverside Mainline (replace in 20 years) • Replace Forward Falmouth Lateral in 20 years • Replace 80W • Rebuild McBain CG

Recommendation

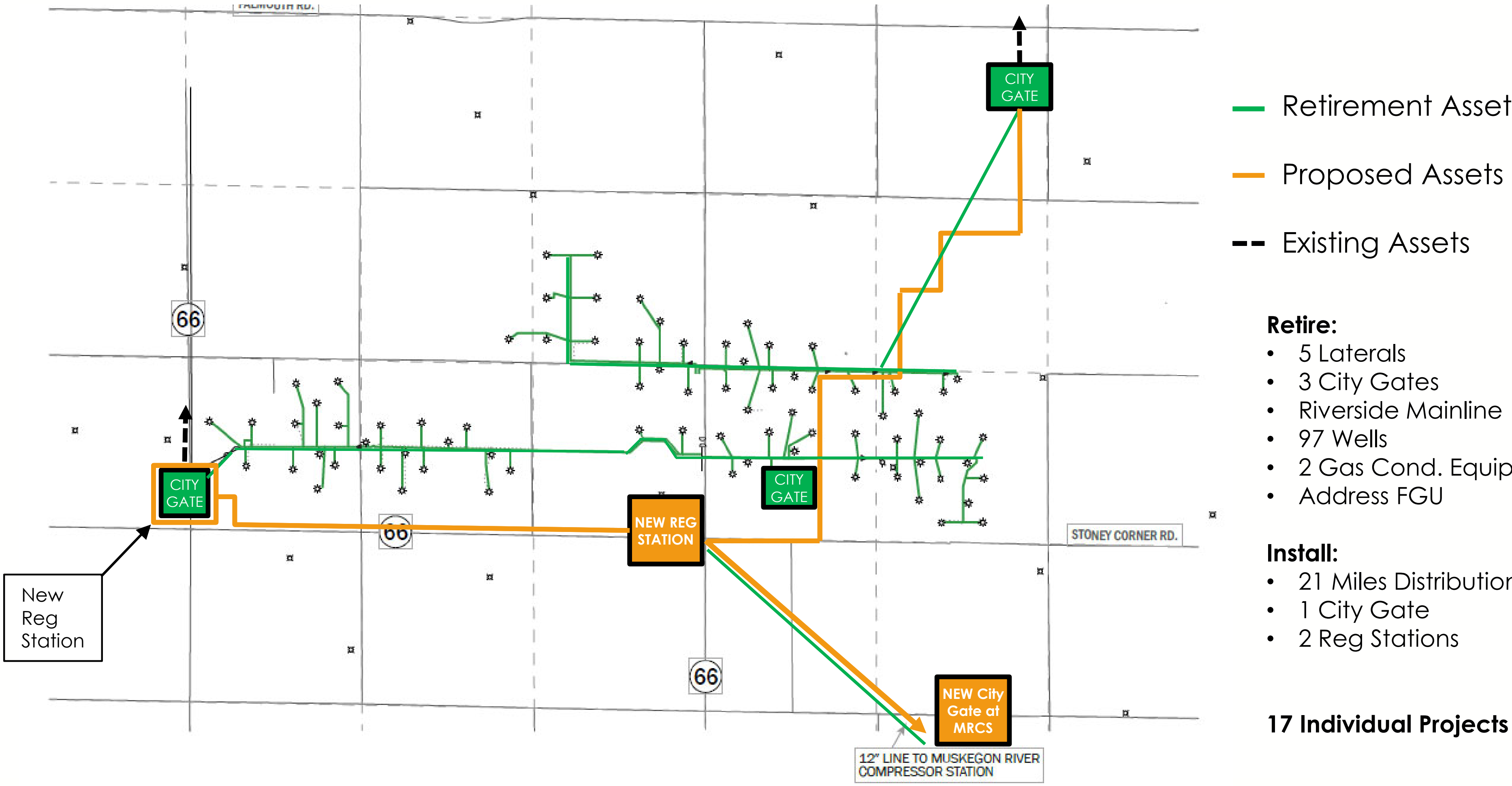
Options 1 & 2



- Option 1 – Supply from Transmission Line near MRCS
- Option 2 - Supply from Line 2400

- Options are similar besides gas supply location.
- Both options are new distribution – rather than Transmission.

Option 1: Retire Riverside Storage Field Supply Gas from near MRCS

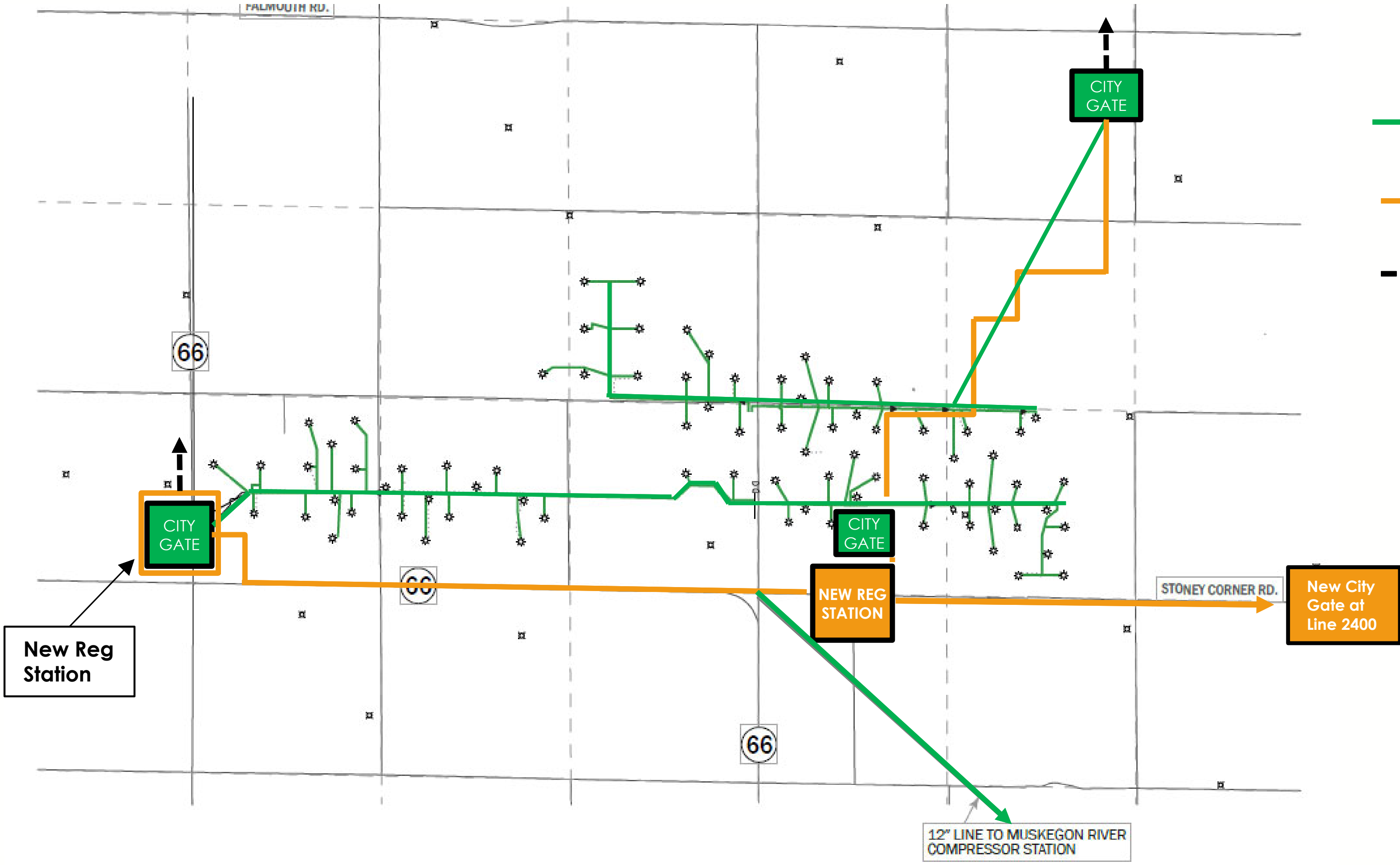


Retire:
- 5 Laterals
- 3 City Gates
- Riverside Mainline
- 97 Wells
- 2 Gas Cond. Equipment
- Address FGU

Install:
- 21 Miles Distribution
- 1 City Gate
- 2 Reg Stations

17 Individual Projects

Option 2: Retire Riverside Field Supply Gas from Line 2400



Retirement Assets

Proposed Assets

Existing Assets

Retire:
- 5 Laterals
- 3 City Gates
- Riverside Mainline
- 97 Wells
- 2 Gas Cond. Equipment
- Address FGU

Install:
- 21 Miles Distribution
- 1 City Gate
- 2 Reg Station

17 Individual Projects

Cost Summary – Pro-Forma

- Option 1 – Retire Western and Central Dome – Supply gas from transmission lines near MRCS
- Option 2 – Retire Western and Central Dome – Supply gas from 2400 Line from the east
- Option 4 – Keep Western Dome replace Mainline as Transmission
- Option 5 – Keep Western Dome install 2 parallel lines from MRCS (Transmission and Distribution)
- Option 6 – Status Quo

	Option 1	Option 2	Option 4	Option 5	Option 6
Capital Investment (millions)	98.2	104.6	143.1	181.5	54.6* ($110.2M)
Levelized Annual O&M Cost (thousands)	74	74	589	606	1042 ($1.2M)**
NPV of Rev Req (millions)	195.4	203.7	235.9	278.3	170.8
Annual Rev Req (millions)	14.4	15.1	17.5	20.7	12.7

- *Cost estimate doesn't include replacement of the Forward – Falmouth Lateral or the Mainline. However, determined in 20 years that it should be replaced. The replacement costs are included in the Pro-Forma in 2041. If include costs it is $110.2M.
- **One time O&M cost to re-coat the Riverside Mainline.
- Service Life in Pro-Forma Model is 50 years
- All Scopes of work (approx. 17 projects per option) have a PSD and cost estimate.

Firm Transport Considered

- Calculated by year and applied per working gas volume retired (O&M), Example below.

	Variable	Ex.			
BTU/CF	A	1042		Firm Transport Annula Cost Calculation:	((A*B)*D*E)/1000
Firm Transport Rate (mmcfd)	B	10		**Annual Cost:**	**$1,940**
Firm Transport Energy (dth/d)	C	10420			
Weighted average of available pipeline Firm Transportion costs ($/dth*day)	D	$0.51			
Days/year	E	365			
Annual Cost:		**$1,940**			

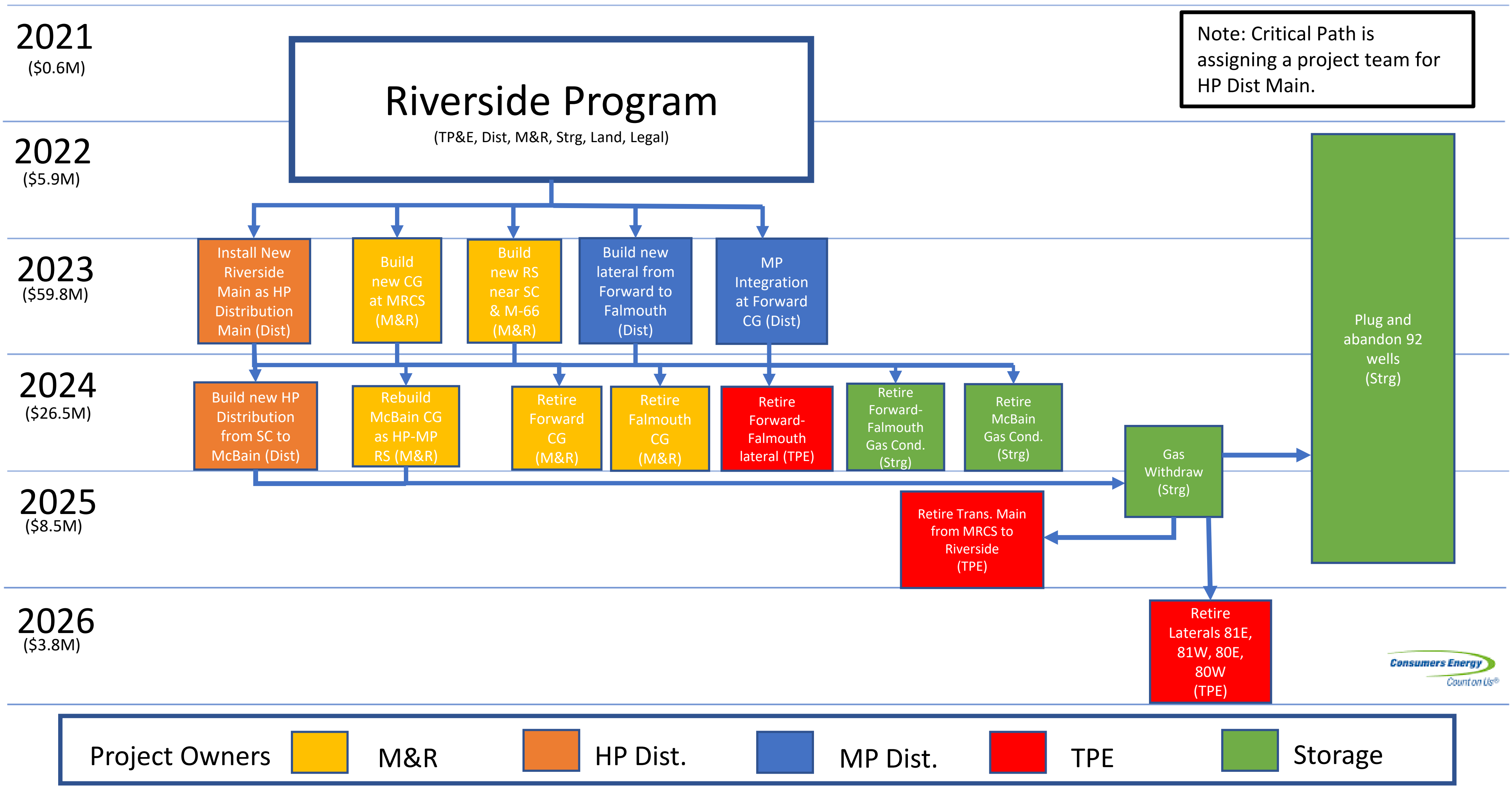
Evaluation

	Option 1	Option 2	Option 4	Option 5	Option 6
Cost (51%) (2.6)	2.3	2.2	2.0	1.6	2.6
Safe (22%) (1.1)	1.1	1.1	0.7	0.6	0.3
Reliable (23%) (1.1)	0.9	0.9	1.0	1.2	0.6
Clean (4%) (0.2)	0.2	0.2	0.2	0.1	0.1
Total	**4.5**	**4.5**	**3.9**	**3.4**	**3.5**

- Scoring out of 5 then multiplied by percentage.
- Total perfect score would be a total of 5.

- Recommend Decommissioning Western and Central Dome.
- Recommend design team confirm the design of the distribution mainline and determine which route to install prior to Gate 2.

Option 1 & 2: Retire Western and Central Dome Supply Gas from MRCS or Line 2400



Question:

351. Refer to Attachment 1 to discovery response AG-CE-434 on the Riverside Gas Storage Retirement project. Please:

a. The low working gas capacity, high well count, the connection to three city gates and withdrawal limitations, and the H2S in the gas stream have been in place for decades and the Company has managed through those issues. What is the main driving issue for this proposed retirement and when did this issue arise?

b. Regarding the three city gates and withdrawal limitations identified in the second bulleted item on page 3 of the attachment, describe the limitations in more detail and explain why they are a concern now and not in the past.

c. Regarding the third and fourth bulleted items on page 3 of the attachment, provide a copy of any recent integrity assessments performed by the Company for the mainline and lateral pipelines, and describe in detail what the integrity issues are and when they started to arise.

d. Provide a map that shows the customer service areas currently served from the Riverside Storage Field with all Company-owned pipelines and interstate pipelines in the vicinity appropriately labeled.

e. On the map or schematic, identify all the pipelines, city gates, regulating stations being replaced, retired, or newly installed, clearly labeled as to their function and disposition under Option 2.

f. With the Mainline from the Muskegon Compressor Station to the Riverside Storage Field being retired, what functions remain for the Muskegon compressor Station? What percent of capacity would it be operating post-Riverside retirement?

g. Regarding the Alternatives Considered on page 5 of the attachment, with Option 6 being a lower cost alternative with pipelines having at least another 10 years of use, why was this option not selected?

h. Refer to the Cost Summary-ProForma on page 9 of the attachment. Please:

    i. Provide the analysis of each option in Excel with formulas intact, all supporting data, and assumptions clearly identified.

    ii. How does the Forward Lateral or the Mainline relate to this project? Identify in the map requested above where these facilities are located.

    iii. Is the replacement cost of $110.2 million included in the NPV calculation of all or only certain of the options presented?

i. Refer to the Firm Transport Considered on page 10 of the attachment.

    i. Is this another option, where an interconnection with an interstate pipeline would be built? If yes, please explain further, identify the interstate pipeline, and provide a NPV analysis over the comparable timeframe to the other options. If no, explain what is the purpose of this slide.

ii. Is the rate paid for capacity a maximum tariff rate or a rate comparable to what CECo pays for transportation capacity to that region of its service area? Provide the rate for firm capacity paid for interstate pipeline gas delivery to the Muskegon Compressor station.

iii. Is the 10,420 Dth/d, the maximum actual daily withdrawal capacity from the Riverside field? If no, explain and provide the maximum withdrawal capacity.

j. Refer to the Evaluation on page 11 of the attachment.

i. Explain how the scores were assigned for each category. Were they subjective or mathematically derived? If mathematically derived, provide the calculations in Excel.

ii. Explain why Option 6 received a third of the points for Safety, about two-third of the points for Reliability, and half of the points from Clean versus Option 2.

k. Refer to the Timeline page of the attachment. Provide an updated timeline as of current date.

Response:

a. The Company objects to this question as to form and for vagueness. Subject to this objection, and without waiving this objection, the Company answers as follows. There are multiple drivers for proposing the retirement of Riverside gas storage field now. The implementation of the Well Rehabilitation Program in 2017 included remediating every well on the system to improve the flow performance and baseline assess the wells. Around the same time, the Natural Gas Delivery Plan ("NGDP") was developed that reviewed the entire gas system to build a roadmap towards a safe, reliable, clean, and affordable gas system. Retiring Riverside field was recognized as a benefit to the system and customers due to significant investment required to replace or remediate the aging pipeline infrastructure and high well count. The low working gas capacity and low flow rate further reduces the benefit of the investment. Instead, a plan was proposed to update the distribution facilities to continue to feed the customers and retire the gas storage system and connected city gates.

b. The direct connection between the city gate and the storage field has limited the withdrawal from Riverside. The other storage fields connected to Muskegon River Compressor Station could drawdown to pressures below 200 psi, Riverside was limited to pressures over 330 psi. This limits the ability to fully cycle the working gas volume of the field. Historically the limitation was managed using gas supply from other storage fields such as Winterfield or Cranberry.

c. The Mainline assessed in 2018 by cMFL (Circumferential Magneti Flux Leakage) and 2020 by narrow axial feature assessment aMFL (Axial Magnetic Flux Leakage). In 2018, there were 11 digs projected and there ended up with 29 digs total, 3 were immediate condition and 3 were 1-year response times. In 2020, the dig total increased by 7 digs to remediate anomalies identified by the alternate technology. The integrity anomalies were primarily due to external corrosion.

The laterals are not inline inspectable and due to materials in the piping, direct assessment is not effective. The increase in corrosion and leaks in this field indicate a rise in integrity concern.

d. Please reference U21308-AG-CE-0562-Joyce_ATT_1.

e. Please reference slide 8 of U21308-AG-CE-0434-Joyce_ATT_1.

f. Please reference page 52 of Exhibit A-46 (NPD-1).

g. Slide 11 of U21308-AG-CE-0434-Joyce_ATT_1 displays the results of the evaluation of the six options considered for the Riverside Storage Field. Cost was one component of the evaluation and was the heaviest weighted of the four used. However, the lower scores for Option 6 (Status Quo) on the safety, reliability, and clean components, as outlined on Slides 3-4 of the attachment resulted in Option 6 not be the best evaluated option.

h. i. Please reference U21308-AG-CE-0562-Joyce_ATT_2.

ii. Forward Lateral and Mainline would remain in service if the Company were to select Option 6 (Status Quo); however, based on their condition, would project for replacement in 2041. Please reference U21308-AG-CE-0562-Joyce_ATT_1.

iii. The $110.2 M would only be included in Option 6 - Status Quo.

i. i. No. The Firm Transport would be secured from the existing pipeline interconnections as an equivalent replacement for volumes typically supplied by the Riverside Storage Field. The slide documents the Firm Transport expenses at the time of the project evaluation.

ii. There is no immediate interconnection at the Riverside Storage Field. The costs used in the project evaluation are an average of the Company's available interconnections.

iii. Yes, the 10,420 Dth/d is the maximum actual daily withdrawal capacity.

j. i. Please reference U21308-AG-CE-0562-Joyce_ATT_2.

ii. The Company scored Option 6 with lower scores on Safety, Reliability and Clean, because the Riverside Storage Field would be left as Status Quo, and the Company would leave itself with greater potential of employee and public safety occurrences, lower potential to reliably to serve customers, and higher potential of methane emissions due to aging pipeline infrastructure and well heads.

k. Please reference U21308-AG-CE-0562-Joyce_ATT_3 for the updated timeline.

Witness: Timothy K. Joyce
Date: April 5, 2023

Question:

157. Refer to pages 33-34 of Mr. Joyce's direct testimony and WP-TKJ-6 on the Northville Storage field and the Lyon 29/34 project. Please provide the following information
a. The cost of the project by year from inception to completion.
b. A copy of the analysis performed by the Company to justify undertaking this project.
c. Explain what alternatives were evaluated, and what financial benefits will result from completion of the project. Provide a copy of the cost/benefit analysis performed in Excel with formulas intact and all assumptions explained.
d. The phases of project development with timeline and related cost and the phase that the project is currently in.
e. Explain what has changed since the Company proposed this project in Case No. U-21308. Provide any updates to the responses to the Attorney General's discovery requests in that case.
f. Evidence that the Company CEO has approved the total cost of this project, or the cost approved to date.
g. The actual moisture content per LB/MMCF experienced during each withdrawal in each year 2018 through 2023 in Excel.
h. The number of days that gas withdrawals occurred during each year in 2021 through 2023.
i. The volume of gas withdrawn on each occasion in 2021 through 2023 and as a percent of total field capacity.
j. The volume of gas withdrawn on each occasion in 2021 through 2023 as a percent of the total gas supply in pipeline system fed partially from the Northville storage field.

Response:

a. Please reference U21490-AG-CE-0315-Joyce_ATT_1 for cost information on both projects.

b. Please reference U21490-AG-CE-0315-Joyce_ATT_5 for a copy of the analysis performed by the Company to justify undertaking this project.

c. Please reference U21490-AG-CE-0315-Joyce_ATT_5 for overview of the alternatives that were evaluated.

d. Timeline for the Lyon 29-34 project is as follows: engineering and equipment procurement in 2023, construction and in-service in 2024-25, and project close-out in 2025.

   Timeline for the Reef project is as follows: engineering and equipment procurement in 2025-26, construction and in-service in 2027, and project close-out in 2028.

e. Detailed engineering drove the a change in scrubber technology. Permitting requirements associated with EGLE Part 615 and proximity to water wells combined with our space constraint drove the need to purchase property and plan for the Lyon 29 site and adding a short section of pipeline to tie-into the CE pipeline system. Highlights of the changes are included in U21490-AG-CE-0315-Joyce_ATT_5.

U21308-AG-CE-0436 – Updates provided in the responses to this question.
U21308-AG-CE-0564 – part a and c. No update. Part b. Updates provided in the responses to this question.
U21308-AG-CE-0647 – No updates
U21308-AG-CE-0648 – No updates
U21308-AG-CE-0649 – No updates

f. The projected Northville Lyon 29/30 and Reef Liquid Handling project expenditures included in Exhibit A-12 (TKJ-5) Schedule B-5.8 were approved by the Senior Management Team, including the CEO, on October 10, 2023, during the annual budget review meeting.

g. Please reference U21490-AG-CE-0315-Joyce_ATT_3 for the actual moisture content per LB/MMCF experienced during each withdrawal in each year 2018 through 2023.

h. Please reference U21490-AG-CE-0315-Joyce_ATT_4 for the number of days that gas withdrawals occurred during each year in 2021 through 2023.

i. Please reference U21490-AG-CE-0315-Joyce_ATT_4 for the volume of gas withdrawn on each occasion in 2021 through 2023 and as a percent of total field capacity.

j. Please reference U21490-AG-CE-0315-Joyce_ATT_4 for the volume of gas withdrawn on each occasion in 2021 through 2023 as a percent of the total gas supply in pipeline system fed partially from the Northville storage field.

Witness: Timothy K. Joyce
Date: April 5, 2024

MICHIGAN PUBLIC SERVICE COMMISSION — **U21490-AG-CE-0315-Joyce_ATT_1** — Case No. U-21490

Consumers Energy Company

Gas Storage

Northville Lyon 29/34 and Reef Liquid Handling Actuals and Projected Spend ($000)

For Gas Rate Case

		Actuals						Projected					
Project Definition		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
GS-00365	NVL- Lyon 29-34 Liquid Handling	91	(89)	-	-	1,149	1,191	11,671	24,912	74			38,998
	Northville Reef Liquid Handling								100	1,200	22,077	150	23,527
													$ 62,525

MICHIGAN PUBLIC SERVICE COMMISSION **U21490-AG-CE-0315-Joyce_ATT_3**

Consumers Energy Company

Gas Storage Case No. U-21490

Northville Field Moisture Content Data

For Gas Rate Case

	Test Date	Moisture Range (lb/mmcf)
Lyon 29 Field	January 2019	7 to 9
Lyon 29-1	March 2020	1.9 to 7.8
Lyon 29-2	March 2020	4.9 to 8.2
Lyon 29-3	March 2020	5 to 7.9
Lyon 34 Field	January 2019	10 to 12
Lyon 2-34	March 2020	9 to 12
Lyon 3-34	March 2020	11 to 14
Lyon 4-34	March 2020	8 to 17
Northville Reef Field	January 2019	7 to 14
N-211	March 2020	5.7 to 6.8
N-301A	March 2020	6.7 to 7.3
N-302A	March 2020	8 to 13
N-303	March 2021	2 to 56*

*Multiple periods of significantly high moisture may be due to the well flowing to the system for the first time since drilling. Moisture decreased to an average of about 12 lb/mmcf using the Delta Unit.

Year	Field	Number of days that gas withdrawals occurred	Volume withdrawn, as a percent of total field capacity	Volume withdrawn, as a percent of total system send out	Withdrawal Volume (MMscf)	Notes	Total Field Capacity (MMscf)	Total system send out (MMscf)
2021	Lyon 29	0	0.00%	0.0000%	0		2179.59	285,926
	Lyon 34	0	0.00%	0.0000%	0		1358	285,926
	Northville Reef	1	2.00%	0.0080%	24.6	Flow testing of new well N-303	1220	285,926
2022	Lyon 29	1	5.60%	0.0420%	121.7	Flowed for ~12 hours before high moisture	2179.59	320,274
	Lyon 34	0	0.00%	0.0000%	0	Flowed for <15 minutes due to valve	1358	320,274
	Northville Reef	1	0.30%	0.0010%	3.9	Flowed for ~2 hours before high moisture	1220	320,274
2023	Lyon 29	0	0.00%	0.0000%	0		2179.59	287,959
	Lyon 34	0	0.00%	0.0000%	0		1358	287,959
	Northville Reef	0	0.00%	0.0000%	0		1220	287,959

Storage Capital Detail (2023-2025)
For Gas Rate Case - December 2023
($000)

Site	Title	2023 7+5 Fcst	2024	2025	12 Mos Ending 12/31/2023	9 Mos Ending 9/30/2024	Projected Bridge Year 21 Mos Ending 9/30/2024	Projected Test Year 12 Mos Ending 9/30/2025	Projected 9 Mos ending in 9/30/23	Projected 12 Mos. Ending 9/30/24	Projected 12 Mos Ending 9/30/2024	Projected 33 Mos ending 9/30/24
Site	Title	2023 7+5 Fcst	2024	2025								
Northville	(1980) GS-00365 - Northville Lyon 29/34 liquid removal	1,373	11,671	24,912	1,373	9,273	10,647	22,191	900	9,747	22,191	32,838
Northville	(13192) Northville Reef Field Liquid Handling Upgrade	0	0	100	0	0	0	79	0	0	79	79
	TOTAL NORTHVILLE	1,373	11,671	25,012	1,373	9,273	10,647	22,271	900	9,747	22,271	32,917

U21490-AG-CE-0316
Page **1** of **1**

Question:

158. Refer to lines 3-8 on page 34 of Mr. Joyce's direct testimony on the Northville Storage field and the Lyon 29/34 project. Please provide a copy of the analysis performed by the Company regarding the blending of gas withdrawn from the Northville field (with higher moisture content) with dry gas from other sources flowing through the pipeline system.

Response:

No formal analysis has been performed. The Company does not recognize blending as a competent means for ensuring gas quality. Various conditions can affect how and whether gases are mixed in a pipe. Due to the integrated nature of Consumers Energy's gas system, its variable operating conditions, and the fact that the system is not designed to assure mixing of gas from different sources, it would be inaccurate to assuming mixing occurs. Installing the gas conditioning equipment will allow for effective utilization, dispatch, and cycling of the fields. Gas measurement accuracy is also impacted with moisture content above the 7lb/mmcf limit, including gas storage inventory and reservoir integrity verification.

Witness: Timothy K. Joyce
Date: April 1, 2024

THE REST OF THE EXHIBIT INCLUDES A 17 PAGE PRESENTATION ON
LYON 29 / 34 LIQUID HANDLING FACILITY

Lyon 29 / 34 Liquid Handling Facility

Chris Plawchan

November 1, 2023

Consumers Energy
Count on Us®

Agenda

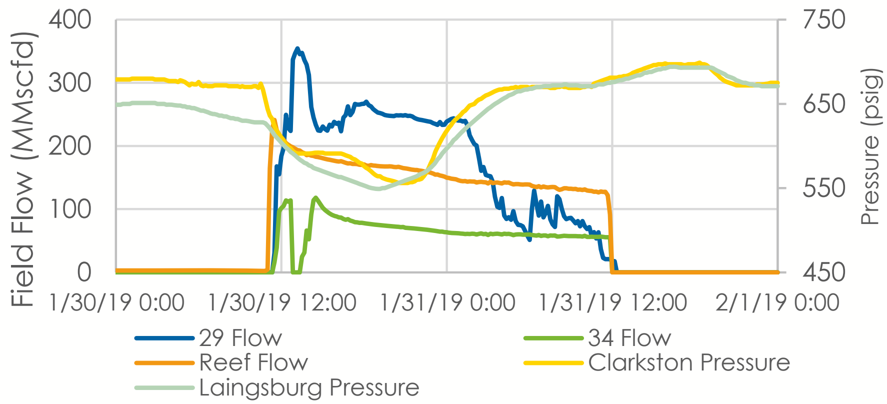
- Lyon 29/34 Purpose
- Project Objectives & Benefits
- Align With Gas Delivery Plan
- Technology Evaluation
- Technology Selection
- Options Evaluated
- Summary of Options
- Lyon 29 Site – Scope
- Lyon 34 Site – Scope
- Northville Reef Site - Scope
- Project Risk / Opportunity
- Project Milestones Schedule
- Project Funding Strategy
- Stakeholder Approval

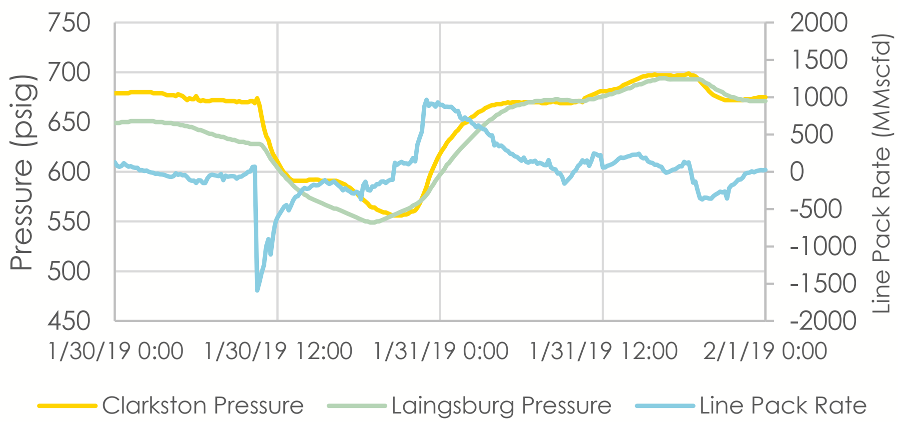
Lyon 29/34 Purpose

Reduce reliance on Ray

- Diversification of peak day supply
- Ray Incident – Immediate system pressure stabilization
- "Insurance Policy" - Less expensive than FT contracts for equivalent pipeline deliverability

Ensure gas delivered to pipeline from Lyon 29, Lyon 34, Northville Reef meet tariff specification





Project Objectives & Benefits

Objectives

- Ensure gas delivered to pipeline from Lyon 29, Lyon 34, Northville Reef meet tariff specification
    - 7 lbs water / 1 million scf gas
- Sarbanes Oxley - process gas before metering – accurate accounting of energy
    - Reconfigure equipment to process all moisture prior to measurement

Benefits

- Reduce non-compliance
    - Avoid potential MPSC fines
    - Avoid customer freeze-offs
- Zero unplanned shut-in of Northville fields
- Reduce potential pipeline corrosion

Align With Gas Delivery Plan

Objective	Goal	Outcome	2030 Target
Safe	Zero Incidents	Reduce System Risk	2.1%
		Achieve GSMS maturity level	≥4.0
Reliable	Resilient and reliable system	Maintain Gas Flow Deliverability	95%
		Increase Resilience	>91.5%
Affordable	Competitive, predictable prices	Annual average of monthly residential bill	$107
		Increase Customer satisfaction survey	85+
		Increase Energy Waste Reduction	1% year over year
Clean	Decrease air emissions footprint	Reduce Scope 1 system methane emissions from 2005 baseline	15,128MT
		Reduce Scope 3 customer carbon emissions from 2022 baseline	4 million MT

Technology Evaluation

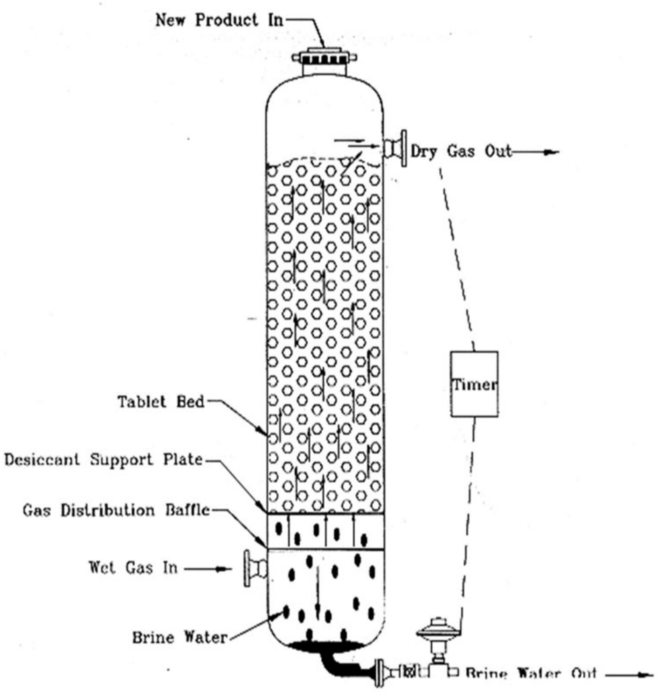
Technology	Economics	Operation	Technical	Overall
Triethelyne Glycol (TEG) -e.g. Ray CS, Overisel CS	8.4	20.2	10.8	39.4
Mole Sieve	5.6	26.6	8.8	41.0
Deliquescent Desiccant	**18**	**31.4**	**12.8**	**62.2**
Gas Membrane	13.6	18.2	10.4	42.2

- Based on flow rates and frequency of use

Technology Selection – Deliquescent Desiccant

Re-evaluation Participates;
- Engineering
- Operations / M&R
- Gas System Planning

Technology Recommendation;
- Orbital Engineering



System characteristics

Improved safety
- No fire hazard
- No pumps, burners, heat exchangers

Reduced facility capital
- Easy installation
- Small footprint – 9'x12' Vessel
- Low capital expense (vessels) - $1.38MM

Reduced operating costs
- Simple unattended operation
- No costly disposal - Brine
- Low maintenance - $8k/yr
- Low periodic costs - $12/mmscf
- No “turndown” limitations

Lower compliance costs
- No BTEX vapor emissions

Restrictions
- May require maintaining desiccant above freezing temperature – Building recommended

Options Evaluated

Dehydration for Individual Facilities

- 3 Process Trains;
    - Bldgs / Knockout Pots / Dehydration Vessels / Filters / Meter / Regulators & PLDs
    - Brine storage Tanks / Offloading Containments
- ACT 9 to construct a new 1200’ 16" pipeline from Lyon 29 Processing Facility to 1020 line
- Acquisition of an adjacent parcel; 9 MI and Griswold Rd.

Central Liquid Handling Facility

- 3 Process Trains (same equipment outlined for the Individual Option)
- ACT 9 to construct two new pipelines from the Lyon 34 site to the Northville Reef
- Acquisition of ROW for the new pipelines

Status Quo – Operate As-Is

- Replacement of S Lyon CG 1/15yrs
- Anticipate 2 cutouts every 10yrs due to corrosion wall thickness loss (.27mills/yr)
- Anticipate yearly ILI tool inspection due to corrosion exceeding the limit of 1mil/yr

Options Evaluated – Con't

3rd Party Storage Supply

- Lyon 29/34 deliverability is being replaced with NNS and FT service from 3rd party pipelines.
- Per the 2021 Storage Strategy Report, Lyon 29 & 34 have a target delivery of 390 MMcf/d that needs to be replaced.
- An average of ANR, PEPL, and Trunkline was used to establish the cost of replacement services. (Per Gas Supply team, no single company would likely have enough capacity available.)

Natural Gas Blending

- Due to the current configuration of the 1020 transmission pipeline and Consumer Energy's stance on blending natural gas streams in order to meet the moisture content tariff limit of 7lb/MMSCF deemed this approach a nonviable solution.

Summary of Options

Alternative (41 year timeline)	Capital Cost	O&M Cost	NPR of Revenue Required	Levelized Annual Revenue Required
Dehydration for Individual Facilities	$59.1 Million	$2.1 Million*	$85.1 Million	$6.8 Million
Central Liquid Handling Facility	$70.0 Million	$2.1 Million*	$104.8 Million	$8.3 Million
Status Quo – Continue Operating As-Is	$20.0 Million	$6.3 Million	$17.2 Million	$1.4 Million
3rd Party Storage Supply – On Demand	$0 Million	$2.7 Billion	$1.1 Billion	$89.6 Million
Natural Gas Blending	N/A	N/A	N/A	N/A

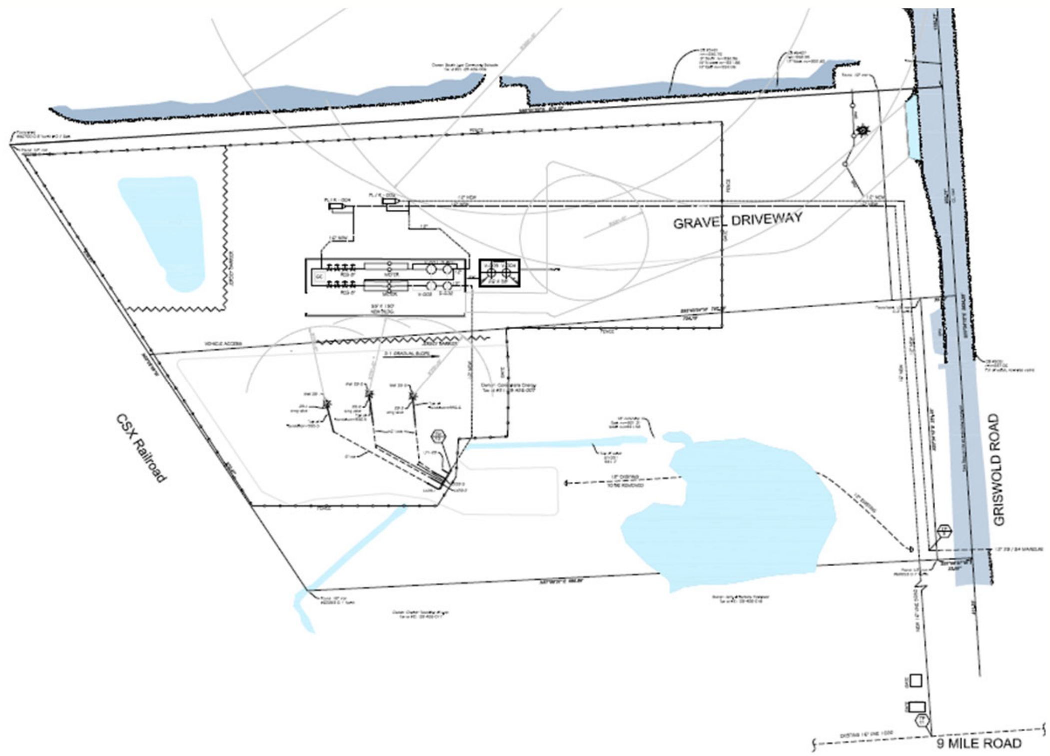
* $8k/yr, $12 per MMcf

- Although the Individual Dehydration Facilities is not the lowest capital cost option, when combined with the overall cost to maintain facilities (via O&M), it provides the optimal solution for the customer.

Lyon 29 Site - Scope

Site modifications entail:

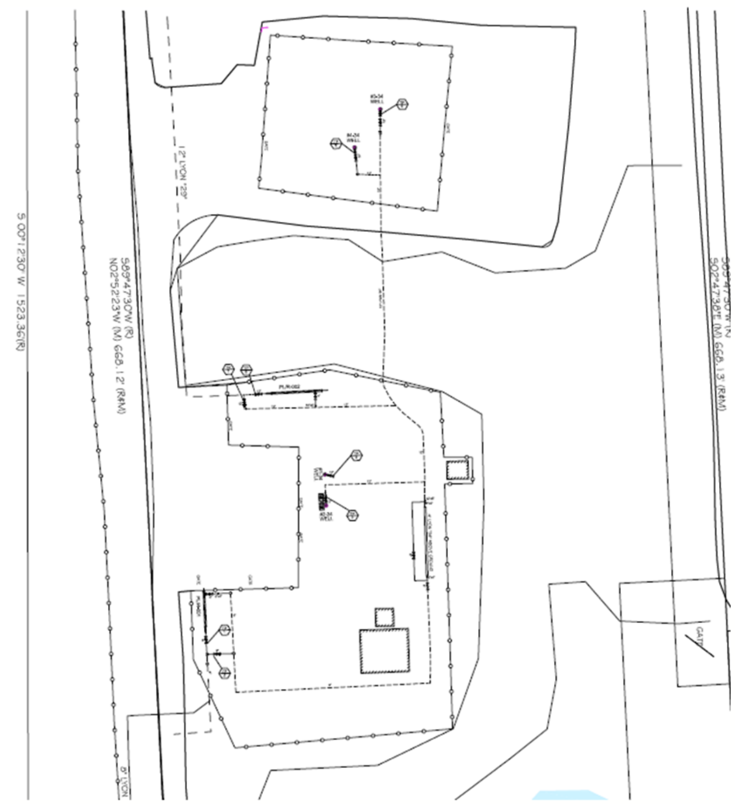
- Acquire 1.5 acres (Griswold and 9mi Rd)
- Act 9 Certificate of Necessity
    - 1200’ new 16” 5050 transmission line
    - Re-route 12” Lyon 29 line
    - 500' of new 12" piping
- 2 Process trains
    - Knockout drum
    - Dehydration vessel
    - Filters
    - Meters; (5) USM meter runs
    - PLD worker/monitor with RCV
- 50'x150' Process Bldg
- 2 - 100 bbl brine tanks
- Tie into 1020 line with 16" piggable wye
- Two Launcher/Receivers; 12" and 16"



Lyon 34 Site - Scope

Site modifications entail:
- A new cold weather enclosure w/ chromograph
- Replace 12" Launcher/Receiver
- Replace 8" Launcher/Receiver
- 4" USM to measure Lyon 34 injection
- Replace well lines

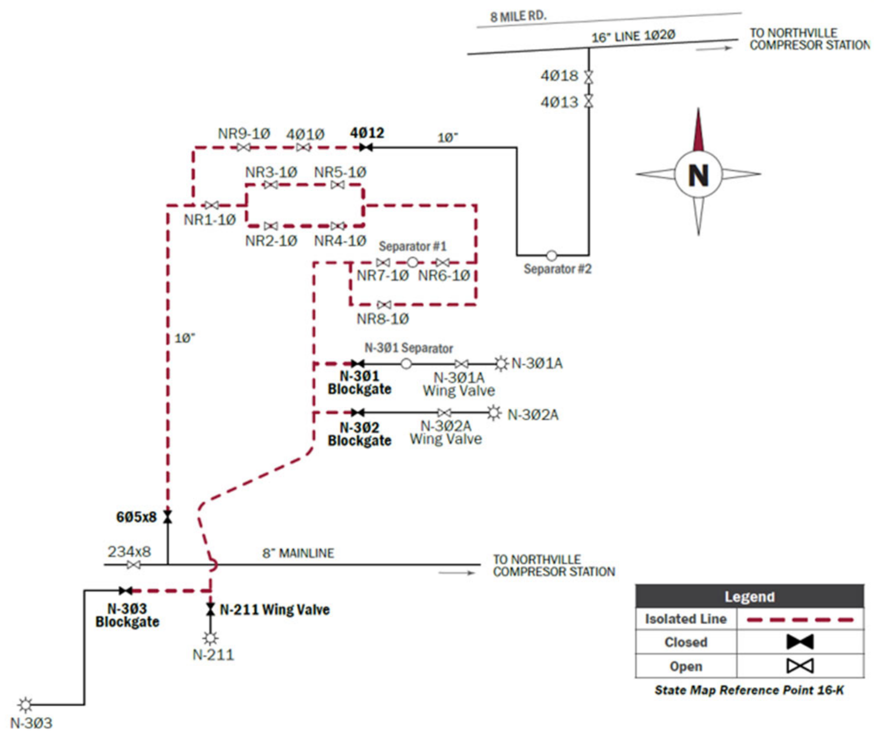
Removal of all existing surface equipment:
- Decommission the 4020 pipeline
- Removal of the 4020/1020 tie-in and block valve
- Removal of existing surface equipment
    - Separators
    - Brine storage tanks
    - PLDs/Regulators
    - 12” Meters / Headers



Northville Reef Site - Scope

Site modifications entail:

- 50'x150' Process Bldg
- New Process train
    - Knockout drum
    - Dehydration vessel
    - Filter / Meters
    - PLD worker/monitor with RCV
- New 2 - 100 bbl brine tanks
- New Launcher/Receivers



Removal of all existing surface equipment:

- Separators
- Brine storage tanks
- PLDs/Regulators
- Meter Headers
- Launcher/Receivers

Project Risk / Opportunities

Risks:

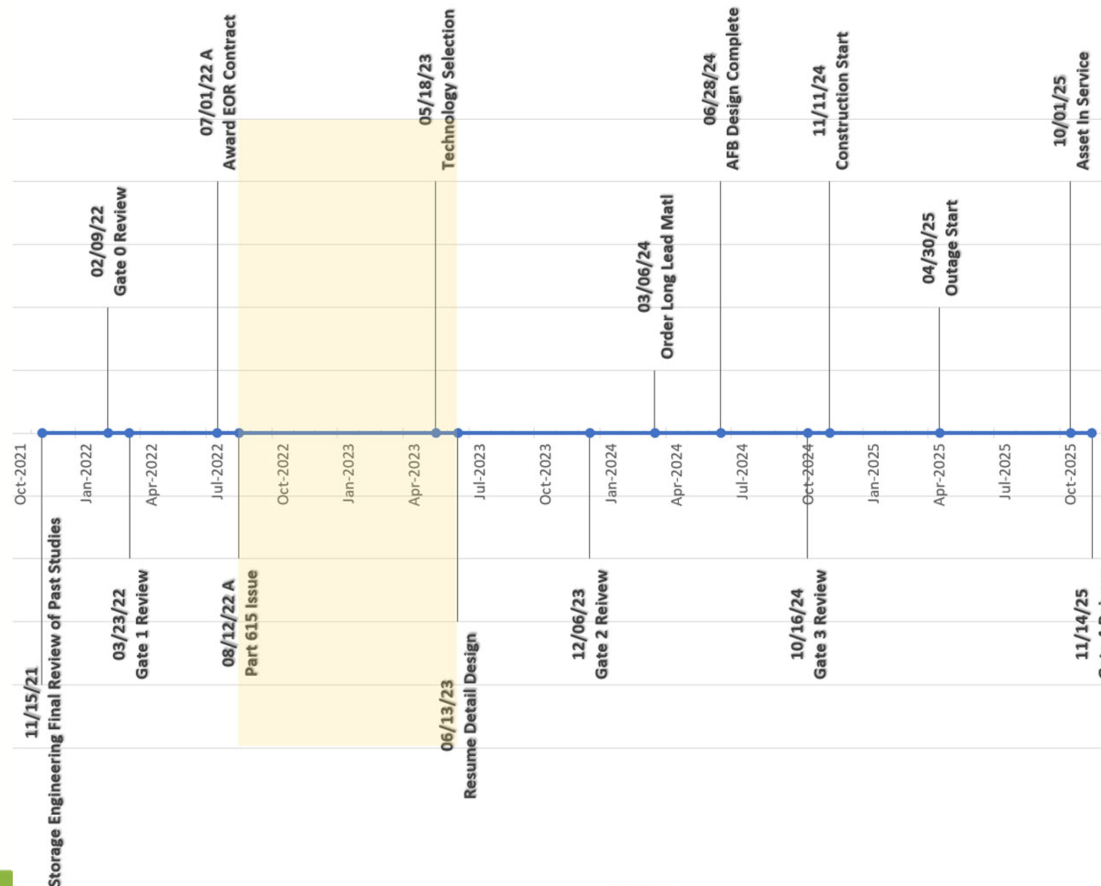
- Act 9 application and review process
- Public scrutiny

Opportunities:

- Effective utilization of Lyon 29 Storage Field
- Equipment located in light industrial zone
- Avoid brand damage – Do nothing option
- Avoid air permit

Project Milestone Schedule

- Part 615 alternate site inquiry: 8/24/22
- Technology issue identified: 11/17/22
- Resume EOR design: 6/13/2023



Project Funding Strategy

	*2022-Original	2022	2023	2024	2025	2026	Total
LTFP	$24,145	$1,139	$8,013	$11,671	$25,246	$75	$46,144
CL's	$(23,006)-Jan	$005	$(6,547)	$0	$0	$0	$(6,542)
Budget	$1,139	$1,144	$1,466	$11,671	$25,246	$75	$39,602

*2022 Original shown above for reference only. LTFP table totals reflect 2024-2028
**Annual Variance due to minor underrun on EOR actuals in 2023.

Annual Summary	2023
Actuals to Date (9/30)	$678
Annual Budget	$1,466
FAC	$1,420
**Variance	$(046)

Assumptions:

- Budget "restarted" 2022 when costs transferred back to GS-00365
- Lyon 29 is final site selection, includes 16" 5050 pipeline / 4020 retire, Lyon 29 piping reconfiguration costs

Stakeholder Approval

Proceed to Gate 2:

- Implement a new dehydration facility at Lyon 29 site for Lyon 29 and Lyon 34 storage fields
- Implement a separate dehydration facility at Northville Reef for the Northville Reef storage field.

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

Question:

173. Refer to Exhibit A-84, page 1. Please expand this schedule to provide the same information for actual 2023 and provide it in Excel.

Response:

Please reference U21490-AG-CE-0331-Joyce_ATT_1 for the 2023 actuals for Exhibit A-84, page 1.

Witness: Timothy K. Joyce
Date: April 3, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CECo Response to AG-CE-0331

Case No: U-21490
Exhibit: AG-26
April 22, 2024

Line No.	Year	2017 (Actuals)	2018 (Actuals)	2019 (Actuals)	2020 (Actuals)	2021 (Actuals)	2022 (Actuals)	2023 (Actuals)	2024	2025	2026	2027	Totals
		Historical							Projected				
1													
2	Number of wells rehabbed	123	109	83	66	71	68	73	58	68	20	0	739
3													
4													
5													
6													
7	**PROGRAM LEVEL - Spend Allocation**												
8													
9													
10	*CE Labor*	2,595,361	4,526,085	5,033,060	3,176,888	3,106,553	3,723,063	6,078,515	4,553,757	5,082,790	1,324,502	-	39,200,574
11	*Outside Services - Admin*	701,828	631,406	702,272	1,858,605	2,156,299	2,273,660	2,441,893	1,710,472	1,909,186	497,506	123,727	15,006,855
12	**Total Labor**	3,297,189	5,157,491	5,735,332	5,035,493	5,262,852	5,996,723	8,520,408	6,264,228	6,991,976	1,822,008	123,727	54,207,429
13													
14	*Wellheads*	1,573,977	738,934	226,592	105,000	143,000	610,620	261,611	698,263	779,384	203,096	-	5,340,478
15	*Packers*	62,015	54,450	61,780	64,000	94,255	78,611	24,425	85,299	95,209	24,810	-	644,855
16	*Tubing*	201,013	70,000	40,894	136,000	420,763	1,376,319	329,216	461,312	514,905	134,177	-	3,684,598
17	*Equipment Mats*	317,584	342,589	160,831	758,858	156,070	312,107	401,725	420,841	469,733	122,406	-	3,462,743
18	*Other Misc*	109,696	1,152,266	492,581	90,940	393,889	1,222,257	345,174	711,313	793,950	206,892	-	5,518,957
19	**Total Materials**	2,264,285	2,358,239	982,677	1,154,798	1,207,977	3,599,914	1,362,151	2,377,029	2,653,180	691,381	-	18,651,631
20													
21	*Civil/Site Prep*	2,022,147	3,174,621	2,313,387	2,353,615	2,995,182	3,719,058	4,766,301	3,406,533	3,802,288	990,821	-	29,543,954
22	*Well Consultants*	977,358	2,201,074	1,191,708	1,057,500	1,904,952	1,725,433	1,386,495	1,861,289	2,077,524	541,373	-	14,924,707
23	*Logging*	2,542,905	2,649,112	2,020,394	1,875,583	2,176,537	2,080,244	1,993,555	2,742,152	3,060,722	797,580	-	21,938,784
24	*Wellhead Technician / Welding*	417,012	476,722	538,578	588,202	1,386,443	1,039,968	813,806	913,776	1,019,935	265,780	-	7,460,221
25	*Painting*	149,340	231,940	544,968	305,040	782,247	1,430,818	293,581	707,763	789,988	205,859	-	5,441,544
26	*Wellhead Assessment*	272,044	-	-	-	-	-	-	55,901	62,395	16,259	-	406,600
27	*Cathodic*	-	27,708	63,170	14,170	-	40,673	19,200	29,944	33,422	8,709	-	236,997
28	*Downhole work*	3,260,928	6,052,907	7,885,993	7,483,163	14,069,796	14,589,169	11,744,719	10,960,975	12,234,368	3,188,100	-	91,470,118
	Misc	-	-	-	-	729,394	3,256,292	369,739	818,999	914,146	238,213	-	6,326,783
29	**Total Construction**	9,641,734	14,814,084	14,558,199	13,677,273	24,044,551	27,881,655	21,387,396	21,497,332	23,994,788	6,252,696	-	177,749,707
30													
31	*Cost Of Removal*	(324,699)	(438,981)	(538,889)	-	(673,314)	(682,924)	(446,136)	(546,345)	(609,817)	(158,909)	-	(4,420,015)
32													
33	**CURRENT PROGRAM LEVEL TOTAL (2017-23 actuals, 2024-2027 estimates)**	**$ 14,878,509**	**$ 21,890,833**	**$ 20,737,319**	**$ 19,867,564**	**$ 29,842,066**	**$ 36,795,368**	**$ 30,823,818**	**$ 29,592,244**	**$ 33,030,128**	**$ 8,607,176**	**$ 123,727**	**$ 246,188,752**
34	AG Calculations	$ 120,963	$ 200,833	$ 249,847	$ 301,024	$ 420,311	$ 541,108	$ 422,244	$ 510,211	$ 485,737	$ 430,359		
35								$ 461,221					
36	**PROGRAM LEVEL - Cost Element Breakdown**												
37													
38	Labor	2,595,361	4,526,085	5,033,060	3,176,888	3,106,553	3,723,063	6,078,515	4,553,757	5,082,790	1,324,502	-	39,200,574
39	Material	2,264,285	2,358,239	982,677	1,154,798	1,207,977	3,599,914	1,362,151	2,377,029	2,653,180	691,381	-	18,651,631
40	Business Expenses	-	-	-	-	-	-	-	-	-	-	-	-
41	Contractors	10,343,562	15,445,490	15,260,470	15,535,878	26,200,850	30,155,315	23,829,289	23,207,804	25,903,975	6,750,203	123,727	192,756,562
42	Contingency	-	-	-	-	-	-	-	-	-	-	-	-
43	Cost of Removal	(324,699)	(438,981)	(538,889)	-	(673,314)	(682,924)	(446,136)	(546,345)	(609,817)	(158,909)	-	(4,420,015)
44	**CURRENT PROGRAM LEVEL TOTAL (2017-23 actuals, 2024-2027 estimates)**	**$ 14,878,509**	**$ 21,890,833**	**$ 20,737,319**	**$ 19,867,564**	**$ 29,842,066**	**$ 36,795,368**	**$ 30,823,818**	**$ 29,592,244**	**$ 33,030,128**	**$ 8,607,176**	**$ 123,727**	**$ 246,188,752**

U21490-AG-CE-0330
Page **1** of **1**

Question:

172. Refer to Exhibit A-12, Schedule B-5.7, page 2. Please expand this schedule to include actual cost for 2018 to 2023, and forecasted calendar years 2024 and 2025, and provide in Excel.

Response:

Please see attachment U21490-AG-CE-0330-Joyce_ATT_1 for historical actuals from Exhibit A-12 (TKJ-5) Schedule B-5.7. Projected expenses for calendar years 2024 and 2025 are included in WP-TKJ-5.

Witness: Timothy K. Joyce
Date: April 2, 2024

U21490-AG-CE-0330-Joyce-ATT_1

~~Schedule B-5.7~~

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21490
Exhibit No.: ~~A-12 (TKJ-5)~~
Schedule: ~~B-5.7~~
Page: 1 of 6
Witness: TKJoyce
Date: ~~December 2023~~

	(a)					(b)		(c)	(d)	(e)	(f)
								Capital Expenditures			
		Historical	**Historical**	**Historical**	**Historical**	**Historical**	**Historical**	**Projected Bridge Year**			**Projected Test Year**
Line		**12 Mos Ended**	**12 Mos Ended**	**12 Mos Ended**	**12 Mos Ended**	**12 Mos Ended**	**12 Mos Ended**	**12 Mos Ending**	**9 Mos Ending**	**21 Mos Ending**	**12 Mos Ending**
No.	**Program Description**	**12/31/2018**	**12/31/2019**	**12/31/2020**	**12/31/2021**	**12/31/2022**	**12/31/2023**	**12/31/2023**	**9/30/2024**	**9/30/2024**	**9/30/2025**
1	Freedom Upgrade Project	62,256	82,980	19,724	13,833	13,567	8,413	7,600	401	8,001	-
2	Compression	50,849	30,571	35,727	49,994	39,968	39,219	42,314	42,934	85,248	59,032
3	Storage	6,481	3,013	4,597	14,212	10,896	13,827	5,742	23,802	29,544	33,067
4	New Well	3,152	3,618	10,576	7,896	10,164	8,157	13,070	14,572	27,641	30,456
5	Well Rehabilitation	22,807	21,194	20,048	28,800	34,985	31,031	35,512	23,873	59,385	32,852
6	Storage Pipeline Replacement	135	1,825	10,141	4,748	6,418	(219)	5,159	8,087	13,246	22,404
7	Well Data Acquisition	536	113	923	3,905	300	239	376	226	601	3,566
8	Riverside Field Retirement	-	-	-	-	2,571	12,449	12,114	33,318	45,432	37,067
9	Safety Valve Installation	-	-	-	-	-	-	-	1,540	1,540	1,938
10	**Total Capital Expenditures**	**146,217**	**143,313**	**101,737**	**123,388**	**118,868**	**113,115**	**121,886**	**148,754**	**270,639**	**220,382**

Question:

238. Refer to Exhibit A-20. For each project of $3 million or greater, please:

a. Provide the total cost from inception to completion by year for total company and the portion applicable to the gas business in Excel. Provide both the annual O&M and capital expenditures separately.

b. Provide the phases of project development (needs assessment, project scoping, project development, project implementation, completed, etc.) for each project with timeline and related cost and the phase that the project is currently in.

Response:

a. Attachment U21490-AG-CE-0397_Baker_ATT_1, columns a through ah, provides the projects $3 million or greater that have not been implemented, with the Total Company and gas allocation capital expenditures and O&M expense from inception to completion in Excel.

b. The cost projection for each multi-phased project was developed for the collective technical effort, and not calculated by phase. However, attachment U21490-AG-CE-0397_Baker_ATT_2 includes an estimation of each multi-phased project into cost per phase that has not already been provided. Attachment U21490-AG-CE-0382_Bammert_ATT_1, column ai, provides the current project phase in 2024. Please refer to response U21490-AG-CE-0221 for this information for the Gas SCADA and Tracking and Traceability projects.

Witness: Stacy H. Baker
Date: April 10, 2024

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Projected Total Company and Gas Allocation Capital Expenditures and O&M Expenses

From Inception to Completion

part a **part a**

		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Projected Total Company - Capital							
		Actual				**Projected**			**Projected**
Line No.	**Description** (a)	**12 Mos Ended 12/31/2020**	**12 Mos Ended 12/31/2021**	**12 Mos Ended 12/31/2022**	**12 Mos Ended 12/31/2023**	**12 Mos Ending 12/31/2024**	**12 Mos Ending 12/31/2025**	**2026+**	**Total Project Capital Costs**
1	ARP-Field Device Asset Management (FDAM)	$ -	$ -	$ -	$ -	$ 4,443,870	$ -	$ -	**$ 4,443,870**
2	ARP-Field Device Asset Management (FDAM)	$ -	$ -	$ -	$ -	$ -	$ 4,995,847	$ -	**$ 4,995,847**
3	ARP-Local Area Network	$ -	$ -	$ -	$ -	$ 4,189,733	$ -	$ -	**$ 4,189,733**
4	ARP-Radio	$ -	$ -	$ -	$ -	$ -	$ 3,629,280	$ -	**$ 3,629,280**
5	ARP-Workstation Asset Management (WAM)	$ -	$ -	$ -	$ -	$ 7,232,949	$ -	$ -	**$ 7,232,949**
6	ARP-Workstation Asset Management (WAM)	$ -	$ -	$ -	$ -	$ -	$ 8,969,107	$ -	**$ 8,969,107**
7	Asset Accounting Upgrade 2025-2027	$ -	$ -	$ -	$ -	$ -	$ 1,469,800	$ 2,312,730	**$ 3,782,530**
8	Customer Order Service Tracker	$ -	$ -	$ -	$ -	$ -	$ 3,762,800	$ -	**$ 3,762,800**
9	Digital-Cloud Data and Analytics Platform	$ -	$ -	$ -	$ 3,342,028	$ 6,614,161	$ -	$ -	**$ 9,956,189**
10	Digital-Hybrid Cloud and Data Center Migration	$ -	$ -	$ -	$ 2,779,013	$ 2,229,370	$ 1,965,528	$ -	**$ 6,973,911**
11	Field Contractor Work Management Technology Enablement	$ -	$ -	$ 27,474	$ 343,464	$ 2,221,400	$ -	$ -	**$ 2,592,338**
12	Field Mapping and Graphics	$ -	$ 662,069	$ 1,558,810	$ 875,278	$ -	$ -	$ -	**$ 3,096,157**
13	Field Supervisor Automation	$ -	$ -	$ -	$ -	$ 1,915,000	$ -	$ -	**$ 1,915,000**
14	Gas SCADA Software Solution	$ -	$ -	$ -	$ 2,512,618	$ 6,185,482	$ 2,793,100	$ -	**$ 11,491,200**
15	Product Family Enhancements-IT/Digital Foundation-Capital	$ -	$ -	$ -	$ -	$ 2,583,204	$ -	$ -	**$ 2,583,204**
16	SAP HANA Database Migration	$ -	$ -	$ -	$ 2,391,575	$ 2,098,000	$ -	$ -	**$ 4,489,575**
17	Tracking & Traceability	$ -	$ -	$ -	$ -	$ -	$ 1,771,250	$ 13,048,340	**$ 14,819,590**
18	Work Management Scheduling Analytics and Reporting	$ -	$ -	$ 825,249	$ 951,565	$ 1,618,258	$ -	$ -	**$ 3,395,072**

		(j)	(k)	(l)	(m)	(o)	(p)	(q)	(r)
		Projected Total Company - O&M							
		Actual				**Projected**			**Projected**
Line No.	**Description**	**12 Mos Ended 12/31/2020**	**12 Mos Ended 12/31/2021**	**12 Mos Ended 12/31/2022**	**12 Mos Ended 12/31/2023**	**12 Mos Ending 12/31/2024**	**12 Mos Ending 12/31/2025**	**2026+**	**Total Project O&M Costs**
1	ARP-Field Device Asset Management (FDAM)	$ -	$ -	$ -	$ -	$ 5,350	$ -	$ -	**$ 5,350**
2	ARP-Field Device Asset Management (FDAM)	$ -	$ -	$ -	$ -	$ -	$ 5,350	$ -	**$ 5,350**
3	ARP-Local Area Network	$ -	$ -	$ -	$ -	$ 49,664	$ -	$ -	**$ 49,664**
4	ARP-Radio	$ -	$ -	$ -	$ -	$ -	$ 236,841	$ -	**$ 236,841**
5	ARP-Workstation Asset Management (WAM)	$ -	$ -	$ -	$ -	$ 33,058	$ -	$ -	**$ 33,058**
6	ARP-Workstation Asset Management (WAM)	$ -	$ -	$ -	$ -	$ -	$ 33,921	$ -	**$ 33,921**
7	Asset Accounting Upgrade 2025-2027	$ -	$ -	$ -	$ -	$ -	$ 207,953	$ 204,250	**$ 412,203**
8	Customer Order Service Tracker	$ -	$ -	$ -	$ -	$ -	$ 642,000	$ -	**$ 642,000**
9	Digital-Cloud Data and Analytics Platform	$ -	$ -	$ -	$ 197,391	$ 1,525,674	$ -	$ -	**$ 1,723,065**
10	Digital-Hybrid Cloud and Data Center Migration	$ -	$ -	$ -	$ 528,832	$ 528,207	$ 528,207	$ -	**$ 1,585,246**
11	Field Contractor Work Management Technology Enablement	$ -	$ 243,019	$ 217,581	$ 23,392	$ 12,384	$ -	$ -	**$ 496,376**
12	Field Mapping and Graphics	$ 5,511	$ 15,703	$ 850	$ 39,580	$ -	$ -	$ -	**$ 61,644**
13	Field Supervisor Automation	$ -	$ -	$ -	$ -	$ 200,625	$ -	$ -	**$ 200,625**
14	Gas SCADA Software Solution	$ -	$ -	$ 631,605	$ 261,043	$ 732,920	$ 395,498	$ -	**$ 2,021,066**
15	Product Family Enhancements-IT/Digital Foundation-Capital	$ -	$ -	$ -	$ -	$ 1,007,116	$ -	$ -	**$ 1,007,116**
16	SAP HANA Database Migration	$ -	$ -	$ -	$ 180,838	$ 80,250	$ -	$ -	**$ 261,088**
17	Tracking & Traceability	$ -	$ -	$ -	$ -	$ -	$ 667,650	$ 959,650	**$ 1,627,300**
18	Work Management Scheduling Analytics and Reporting	$ -	$ -	$ 70,957	$ 46,236	$ 30,730	$ -	$ -	**$ 147,923**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Total Company and Gas Allocation Capital Expenditures and O&M Expenses
From Inception to Completion
part a

	(a)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)
		Projected Gas Allocation - Capital							
		Actual				**Projected**			**Projected**
Line No.	**Description**	**12 Mos Ended 12/31/2020**	**12 Mos Ended 12/31/2021**	**12 Mos Ended 12/31/2022**	**12 Mos Ended 12/31/2023**	**12 Mos Ending 12/31/2024**	**12 Mos Ending 12/31/2025**	**2026+**	**Total Project Capital Costs**
1	ARP-Field Device Asset Management (FDAM)	$ -	$ -	$ -	$ -	$ 1,348,715	$ -	$ -	**$ 1,348,715**
2	ARP-Field Device Asset Management (FDAM)	$ -	$ -	$ -	$ -	$ -	$ 1,516,240	$ -	**$ 1,516,240**
3	ARP-Local Area Network	$ -	$ -	$ -	$ -	$ 1,943,617	$ -	$ -	**$ 1,943,617**
4	ARP-Radio	$ -	$ -	$ -	$ -	$ -	$ 1,683,623	$ -	**$ 1,683,623**
5	ARP-Workstation Asset Management (WAM)	$ -	$ -	$ -	$ -	$ 2,195,200	$ -	$ -	**$ 2,195,200**
6	ARP-Workstation Asset Management (WAM)	$ -	$ -	$ -	$ -	$ -	$ 2,722,124	$ -	**$ 2,722,124**
7	Asset Accounting Upgrade 2025-2027	$ -	$ -	$ -	$ -	$ -	$ 446,084	$ 701,914	**$ 1,147,998**
8	Customer Order Service Tracker	$ -	$ -	$ -	$ -	$ -	$ 1,142,010	$ -	**$ 1,142,010**
9	Digital-Cloud Data and Analytics Platform	$ -	$ -	$ -	$ 1,072,123	$ 2,007,398	$ -	$ -	**$ 3,079,520**
10	Digital-Hybrid Cloud and Data Center Migration	$ -	$ -	$ -	$ 891,507	$ 676,614	$ 596,538	$ -	**$ 2,164,659**
11	Field Contractor Work Management Technology Enablement	$ -	$ -	$ 8,245	$ 110,183	$ 674,195	$ -	$ -	**$ 792,623**
12	Field Mapping and Graphics	$ -	$ 198,687	$ 467,799	$ 280,789	$ -	$ -	$ -	**$ 947,275**
13	Field Supervisor Automation	$ -	$ -	$ -	$ -	$ 581,203	$ -	$ -	**$ 581,203**
14	Gas SCADA Software Solution	$ -	$ -	$ -	$ 2,512,618	$ 6,185,482	$ 2,793,100	$ -	**$ 11,491,200**
15	Product Family Enhancements-IT/Digital Foundation-Capital	$ -	$ -	$ -	$ -	$ 784,002	$ -	$ -	**$ 784,002**
16	SAP HANA Database Migration	$ -	$ -	$ -	$ 767,217	$ 636,743	$ -	$ -	**$ 1,403,960**
17	Tracking & Traceability	$ -	$ -	$ -	$ -	$ -	$ 1,771,250	$ 13,048,340	**$ 14,819,590**
18	Work Management Scheduling Analytics and Reporting	$ -	$ -	$ 247,657	$ 305,262	$ 491,141	$ -	$ -	**$ 1,044,061**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Total Company and Gas Allocation Capital Expenditures and O&M Expenses
From Inception to Completion

Attachment No.: U21490-AG-CE-0397_ATT_1
Witness: SHBaker
Date: April 2024

part a | part b

	(a)	(aa)	(ab)	(ac)	(ad)	(ae)	(af)	(ag)	(ah)	(ai)
		Projected Gas Allocation - O&M								
		Actual				Projected			Projected	
Line No.	Description	12 Mos Ended 12/31/2020	12 Mos Ended 12/31/2021	12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	12 Mos Ending 12/31/2025	2026+	Total Project O&M Costs	Current Phase in 2024
1	ARP-Field Device Asset Management (FDAM)	$ -	$ -	$ -	$ -	$ 1,980	$ -	$ -	**$ 1,980**	N/A
2	ARP-Field Device Asset Management (FDAM)	$ -	$ -	$ -	$ -	$ -	$ 1,980	$ -	**$ 1,980**	N/A
3	ARP-Local Area Network	$ -	$ -	$ -	$ -	$ 18,376	$ -	$ -	**$ 18,376**	N/A
4	ARP-Radio	$ -	$ -	$ -	$ -	$ -	$ 87,631	$ -	**$ 87,631**	N/A
5	ARP-Workstation Asset Management (WAM)	$ -	$ -	$ -	$ -	$ 12,231	$ -	$ -	**$ 12,231**	N/A
6	ARP-Workstation Asset Management (WAM)	$ -	$ -	$ -	$ -	$ -	$ 12,551	$ -	**$ 12,551**	N/A
7	Asset Accounting Upgrade 2025-2027	$ -	$ -	$ -	$ -	$ -	$ 76,943	$ 75,573	**$ 152,515**	Investment Planning
8	Customer Order Service Tracker	$ -	$ -	$ -	$ -	$ -	$ 237,540	$ -	**$ 237,540**	Investment Planning
9	Digital-Cloud Data and Analytics Platform	$ -	$ -	$ -	$ 69,087	$ 564,499	$ -	$ -	**$ 633,586**	Define
10	Digital-Hybrid Cloud and Data Center Migration	$ -	$ -	$ -	$ 185,091	$ 195,437	$ 195,437	$ -	**$ 575,964**	Execute
11	Field Contractor Work Management Technology Enablement	$ -	$ 82,626	$ 76,153	$ 8,187	$ 4,582	$ -	$ -	**$ 171,549**	Execute
12	Field Mapping and Graphics	$ 1,874	$ 5,339	$ 298	$ 13,853	$ -	$ -	$ -	**$ 21,363**	Close
13	Field Supervisor Automation	$ -	$ -	$ -	$ -	$ 74,231	$ -	$ -	**$ 74,231**	Execute
14	Gas SCADA Software Solution	$ -	$ -	$ 631,605	$ 261,043	$ 732,920	$ 395,498	$ -	**$ 2,021,066**	Refer to U21490-AG-CE-0221
15	Product Family Enhancements-IT/Digital Foundation-Capital	$ -	$ -	$ -	$ -	$ 372,633	$ -	$ -	**$ 372,633**	N/A
16	SAP HANA Database Migration	$ -	$ -	$ -	$ 63,293	$ 29,693	$ -	$ -	**$ 92,986**	Execute
17	Tracking & Traceability	$ -	$ -	$ -	$ -	$ -	$ 667,650	$ 959,650	**$ 1,627,300**	Refer to U21490-AG-CE-0221
18	Work Management Scheduling Analytics and Reporting	$ -	$ -	$ 24,835	$ 16,183	$ 11,370	$ -	$ -	**$ 52,388**	Execute

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Attachment No: U21490-AG-CE-0397_ATT_2
Page: Page 1 of 9
Witness: SHBaker
Date: April 2024

Asset Accounting Upgrade 2025-2027

Phase	Phase Completion	Total Company Projected Capital	Total Company Projected O&M	Gas Allocation Projected Capital	Gas Allocation Projected O&M
Plan	8/8/2025	$ -	$ 41,220	$ -	$ 15,252
Define	2/6/2026	$ 378,253	$ 61,830	$ 114,800	$ 22,877
Execution & Go-Live	3/5/2027	$ 3,404,277	$ 269,153	$ 1,033,198	$ 99,386
Close	3/26/2027	$ -	$ 40,000	$ -	$ 15,000
Total		**$ 3,782,530**	**$ 412,203**	**$ 1,147,998**	**$ 152,515**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Customer Order Service Tracker

Attachment No: U21490-AG-CE-0397_ATT_2
Page: Page 2 of 9
Witness: SHBaker
Date: April 2024

Phase	Phase Completion	Total Company Projected Capital	Total Company Projected O&M	Gas Allocation Projected Capital	Gas Allocation Projected O&M
Plan	2/7/2025	$ -	$ 417,300	$ -	$ 154,401
Define	4/4/2025	$ 940,700	$ 128,400	$ 285,503	$ 47,508
Execution & Go-Live	10/10/2025	$ 2,822,100	$ 64,200	$ 856,507	$ 23,754
Close	10/17/2025	$ -	$ 32,100	$ -	$ 11,877
Total		**$ 3,762,800**	**$ 642,000**	**$ 1,142,010**	**$ 237,540**

Question:

80. Refer to lines 19-22 on page 11 of Mr. McLean's direct testimony on the two Digital Customer Operations projects. Please provide the capital expenditures for each project from inception to completion along with the O&M expense and the on-going amount of O&M expense annually after implementation of the system. If the cost of this system is also allocated to the electric business, provide the requested cost information for total company with the portion allocated to the gas business.

Response:

Please see attachment U21490-AG-CE-0227-Baker_ATT_1 for the projected total Company and gas allocation capital expenditures and O&M expense from inception to completion, including the projected annual on-going maintenance for the Customer Service Order Tracker and Customer Work Request Web Portal projects. The projected annual on-going maintenance for the Customer Service Order Tracker and Customer Work Request Web Portal projects are not included in Operations O&M projections in this case.

Witness: Stacy H. Baker
Date: March 26, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Total Company and Gas Allocation Capital Expenditures and O&M Expenses
From Inception to Completion

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
		Projected Total Company - Capital						Projected Total Company - O&M						
		Actual	Projected			Projected	Projected	Actual	Projected			Projected	Projected	Projected
Line No.	Description	12 Mos Ended 12/31/2022	12 Mos Ending 12/31/2023	12 Mos Ending 12/31/2024	12 Mos Ending 12/31/2025	2026+	Total Project Capital Costs	12 Mos Ended 12/31/2022	12 Mos Ending 12/31/2023	12 Mos Ending 12/31/2024	12 Mos Ending 12/31/2025	2026+	Total Project O&M Costs	Annual Ongoing Maintenance
1	Customer Order Service Tracker	$ -	$ -	$ -	$ 3,762,800	$ -	**$ 3,762,800**	$ -	$ -	$ -	$ 642,000	$ -	**$ 642,000**	$ 24,797
2	Customer Work Request Web Portal	$ -	$ -	$ -	$ 1,915,133	$ -	**$ 1,915,133**	$ -	$ -	$ -	$ 430,782	$ -	**$ 430,782**	$ 22,317

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Total Company and Gas Allocation Capital Expenditures and O&M Expenses
From Inception to Completion

Attachment No.: U21490-AG-CE-0227_ATT_1
Witness: SHBaker
Date: March 2024

	(a)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)
		Projected Gas Allocation - Capital						**Projected Gas Allocation - O&M**						
		Actual	**Projected**			**Projected**	**Projected**	**Actual**	**Projected**			**Projected**	**Projected**	**Projected**
Line No.	**Description**	**12 Mos Ended 12/31/2022**	**12 Mos Ending 12/31/2023**	**12 Mos Ending 12/31/2024**	**12 Mos Ending 12/31/2025**	**2026+**	**Total Project Capital Costs**	**12 Mos Ended 12/31/2022**	**12 Mos Ending 12/31/2023**	**12 Mos Ending 12/31/2024**	**12 Mos Ending 12/31/2025**	**2026+**	**Total Project O&M Costs**	**Annual Ongoing Maintenance**
1	Customer Order Service Tracker	$ -	$ -	$ -	$ 1,142,010	$ -	**$ 1,142,010**	$ -	$ -	$ -	$ 237,540	$ -	**$ 237,540**	$ 9,486
2	Customer Work Request Web Portal	$ -	$ -	$ -	$ 581,243	$ -	**$ 581,243**	$ -	$ -	$ -	$ 159,389	$ -	**$ 159,389**	$ 8,537

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

Question:

81. Refer to the Customer Work Request Portal on page 12 of Mr. McLean's direct testimony. Please:

a. Provide a copy of the cost/benefit analysis showing the economic analysis to justify undertaking this project in Excel with formulas intact.

b. How many inquiries received by Customer Service Representatives (CSR) in each year 2022 and 2023 would be avoided by this system?

c. Provide the cost per call currently incurred.

Response:

a. Please see attachment U21490-AG-CE-0228-Baker_ATT_1 for a copy of the cost/benefit analysis in Excel with formulas intact.

b. Please refer to Company witness Steven Q. McLean's response.

c. Please refer to Company witness McLean's response.

Witness: Stacy H. Baker
Date: March 26, 2024

U21490-AG-CE-0228 -McLean
Page **1** of **1**

Question:

81. Refer to the Customer Work Request Portal on page 12 of Mr. McLean's direct testimony. Please:

a. Provide a copy of the cost/benefit analysis showing the economic analysis to justify undertaking this project in Excel with formulas intact.

b. How many inquiries received by Customer Service Representatives (CSR) in each year 2022 and 2023 would be avoided by this system?

c. Provide the cost per call currently incurred.

Response:

a. Please refer to Company witness Stacy H. Baker's response.

b. Recognizing that call volumes fluctuate and that there are numerous reasons customers may call the contact center, the Company estimates a 20% reduction in the average 8,000 calls per year to the contact center related to initial new service requests over a three-year period. Beyond the initial call to the contact center for a new service request, the Customer Work Request Portal's automation of work request processes, as described in my testimony, is expected to reduce calls to Energy Request Center project coordinators throughout the new service work order process. Please note electric costs associated with this project were approved by the Commission in its Case No. U-21389 March 1, 2024 Order.

c. The current, estimated cost per call is $7.20 (internal and contracted contact center resources).

Witness: Steven Q. McLean
Date: March 26, 2024

U21490-AG-CE-0228-Baker_ATT_1

Customer Work Request Web Portal

Year	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Year Counter	1	2	3	4	5	6
Life Flag	1	1	1	1	1	1
Remaining Expense Flag	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	0	2,508,653	-1.000
Remaining	0	2,508,653	-1.000

COSTS

	NPV	Total	2024	2025	2026	2027	2028	2029
CAPITAL + COR			0	1,915,133	0	0	0	0
CAPITAL + COR *Escalated*			0	1,951,521	0	0	0	0
Total Investment			0	1,951,521	1,951,521	1,951,521	1,951,521	1,951,521
Beginning Rate Base			0	1,951,521	1,561,216	1,170,912	780,608	390,304
Depreciation			0	(390,304)	(390,304)	(390,304)	(390,304)	(390,304)
Ending Rate Base			0	1,561,216	1,170,912	780,608	390,304	0
Average Rate Base			0	1,756,368	1,366,064	975,760	585,456	195,152
O&M			0	430,782	45,000	45,000	45,000	45,000
O&M *Escalated*			0	438,967	46,726	47,614	48,519	49,441
Other Costs			0	0	0	0	0	0
Other Costs *Escalated*			0	0	0	0	0	0
NPVRR OVERALL COSTS								
Return Costs	$334,522	420,162	0	151,258	117,645	84,032	50,419	16,806
Depreciation Costs	$1,468,954	1,951,521	0	390,304	390,304	390,304	390,304	390,304
Property Tax	$180,094	239,256	0	47,851	47,851	47,851	47,851	47,851
Insurance	$6,133	8,148	0	1,630	1,630	1,630	1,630	1,630
O&M	$518,950	631,266	0	438,967	46,726	47,614	48,519	49,441
Other	$0	0	0	0	0	0	0	0
Total	$2,508,653	$3,250,353	$0	$1,030,010	$604,157	$571,431	$538,723	$506,032
NPVRR REMAINING COSTS								
Return Costs	$334,522	420,162	0	151,258	117,645	84,032	50,419	16,806
Depreciation Costs	$1,468,954	1,951,521	0	390,304	390,304	390,304	390,304	390,304
Property Tax	$180,094	239,256	0	47,851	47,851	47,851	47,851	47,851
Insurance	$6,133	8,148	0	1,630	1,630	1,630	1,630	1,630
O&M	$518,950	631,266	0	438,967	46,726	47,614	48,519	49,441
Other	$0	0	0	0	0	0	0	0
Total	$2,508,653	$3,250,353	$0	$1,030,010	$604,157	$571,431	$538,723	$506,032

BENEFITS

	NPV	Total	2024	2025	2026	2027	2028	2029
CAPITAL + COR			0	0	0	0	0	0
CAPITAL + COR *Escalated*			0	0	0	0	0	0
Total Investment			0	0	0	0	0	0
Beginning Rate Base			0	0	0	0	0	0
Depreciation			0	0	0	0	0	0
Ending Rate Base			0	0	0	0	0	0
Average Rate Base			0	0	0	0	0	0
Total O&M			0	0	0	0	0	0
Total O&M *Escalated*			0	0	0	0	0	0
Other			0	0	0	0	0	0
Other *Escalated*			0	0	0	0	0	0
NPVRR OVERALL BENEFITS								
Return	$0	0	0	0	0	0	0	0
Depreciation	$0	0	0	0	0	0	0	0
Property Tax	$0	0	0	0	0	0	0	0
Insurance	$0	0	0	0	0	0	0	0
O&M	$0	0	0	0	0	0	0	0
Other	$0	0	0	0	0	0	0	0
Total	$0	$0	$0	$0	$0	$0	$0	$0

U21490-AG-CE-0228 -McLean
Page **1** of **1**

Question:

81. Refer to the Customer Work Request Portal on page 12 of Mr. McLean's direct testimony. Please:

a. Provide a copy of the cost/benefit analysis showing the economic analysis to justify undertaking this project in Excel with formulas intact.

b. How many inquiries received by Customer Service Representatives (CSR) in each year 2022 and 2023 would be avoided by this system?

c. Provide the cost per call currently incurred.

Response:

a. Please refer to Company witness Stacy H. Baker's response.

b. Recognizing that call volumes fluctuate and that there are numerous reasons customers may call the contact center, the Company estimates a 20% reduction in the average 8,000 calls per year to the contact center related to initial new service requests over a three-year period. Beyond the initial call to the contact center for a new service request, the Customer Work Request Portal's automation of work request processes, as described in my testimony, is expected to reduce calls to Energy Request Center project coordinators throughout the new service work order process. Please note electric costs associated with this project were approved by the Commission in its Case No. U-21389 March 1, 2024 Order.

c. The current, estimated cost per call is $7.20 (internal and contracted contact center resources).

Witness: Steven Q. McLean
Date: March 26, 2024

U21490-AG-CE-0229 (Partial)
Page **1** of **1**

Question:

82. Refer to the Customer Order Service Tracker project on pages 13-15 of Mr. McLean's direct testimony. Please:

a. Explain how service orders are tracked now.

b. Provide a copy of the cost/benefit analysis showing the economic analysis to justify undertaking this project in Excel with formulas intact.

c. How many of the inquiries received by CSR in each year 2022 and 2023 would be avoided by this system.

d. Provide the cost per call currently incurred.

e. Explain why customers are dissatisfied if the Company adheres to the scheduled time in arriving at the customer location.

Response:

a. Please refer to Company witness Steven Q. McLean's response.

b. Please see attachment U21490-AG-CE-0229_Baker_ATT_1 for a copy of the cost/benefit analysis in Excel with formulas intact.

c. Please refer to Company witness McLean's response.

d. Please refer to Company witness McLean's response.

e. Please refer to Company witness McLean's response.

Witness: Stacy H. Baker
Date: March 26, 2024

U21490-AG-CE-0229-Baker_ATT_1

Customer Order Service Tracker

Year	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Year Counter	1	2	3	4	5	6	7	8
Life Flag	1	1	1	1	1	1	1	1
Remaining Expense Flag	0	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	0	4,844,639	-1.000
Remaining	0	4,844,639	-1.000

COSTS

	NPV	**Total**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPITAL + COR			0	3,762,800	0	0	0	0	0	0
CAPITAL + COR *Escalated*			0	3,834,293	0	0	0	0	0	0
Total Investment			0	3,834,293	3,834,293	3,834,293	3,834,293	3,834,293	3,834,293	3,834,293
Beginning Rate Base			0	3,834,293	3,286,537	2,738,781	2,191,025	1,643,269	1,095,512	547,756
Depreciation			0	(547,756)	(547,756)	(547,756)	(547,756)	(547,756)	(547,756)	(547,756)
Ending Rate Base			0	3,286,537	2,738,781	2,191,025	1,643,269	1,095,512	547,756	0
Average Rate Base			0	3,560,415	3,012,659	2,464,903	1,917,147	1,369,390	821,634	273,878
O&M			0	642,000	50,000	50,000	50,000	50,000	50,000	50,000
O&M *Escalated*			0	654,198	51,918	52,904	53,910	54,934	55,978	57,041
Other Costs			0	0	0	0	0	0	0	0
Other Costs *Escalated*			0	0	0	0	0	0	0	0
NPVRR OVERALL COSTS										
Return Costs	$880,427	1,155,733	0	306,623	259,450	212,277	165,105	117,932	70,759	23,586
Depreciation Costs	$2,698,834	3,834,293	0	547,756	547,756	547,756	547,756	547,756	547,756	547,756
Property Tax	$463,228	658,118	0	94,017	94,017	94,017	94,017	94,017	94,017	94,017
Insurance	$15,775	22,411	0	3,202	3,202	3,202	3,202	3,202	3,202	3,202
O&M	$786,376	980,883	0	654,198	51,918	52,904	53,910	54,934	55,978	57,041
Other	$0	0	0	0	0	0	0	0	0	0
Total	$4,844,639	$6,651,439	$0	$1,605,796	$956,343	$910,157	$863,989	$817,841	$771,712	$725,602
NPVRR REMAINING COSTS										
Return Costs	$880,427	1,155,733	0	306,623	259,450	212,277	165,105	117,932	70,759	23,586
Depreciation Costs	$2,698,834	3,834,293	0	547,756	547,756	547,756	547,756	547,756	547,756	547,756
Property Tax	$463,228	658,118	0	94,017	94,017	94,017	94,017	94,017	94,017	94,017
Insurance	$15,775	22,411	0	3,202	3,202	3,202	3,202	3,202	3,202	3,202
O&M	$786,376	980,883	0	654,198	51,918	52,904	53,910	54,934	55,978	57,041
Other	$0	0	0	0	0	0	0	0	0	0
Total	$4,844,639	$6,651,439	$0	$1,605,796	$956,343	$910,157	$863,989	$817,841	$771,712	$725,602

BENEFITS

	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPITAL + COR	0	0	0	0	0	0	0	0
CAPITAL + COR *Escalated*	0	0	0	0	0	0	0	0
Total Investment	0	0	0	0	0	0	0	0
Beginning Rate Base	0	0	0	0	0	0	0	0
Depreciation	0	0	0	0	0	0	0	0
Ending Rate Base	0	0	0	0	0	0	0	0
Average Rate Base	0	0	0	0	0	0	0	0
Total O&M	0	0	0	0	0	0	0	0
Total O&M *Escalated*	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0
Other *Escalated*	0	0	0	0	0	0	0	0

Question:

166. Refer to page 54 of Mr. Joyce's direct testimony on the Gas Compressor Historian project. Please:
a. Provide any changes to this project from the information presented in Case No. U-21308.
b. Provide the phases of project development for the project with timeline and related cost and the phase that the project is currently in.

Response:

a. The Gas Compression Historian project in Case No. U-21308 was planned to begin in 2024 and in this case, has been deferred to begin in 2025. This project was deferred during the Company's annual planning cycle based on other projects being a higher priority and the level of IT funding available.

b. The project is currently in the investment planning stage. Please refer to the table below for the project timeline of the phases of the projected total Company and gas allocation costs for the Gas Compression Historian project.

Gas Compression Historian					
	Phase	Total Company Projected		Gas Allocation Projected	
Phase	Completion	Capital	O&M	Capital	O&M
Plan	3/31/2025	0	36,000	0	36,000
Define	6/1/2025	254,750	22,000	254,750	22,000
Execution & Go Live	11/15/2025	1,960,000	111,800	1,960,000	111,800
Close	12/31/2025	0	7,810	0	7,810
Total		**$2,214,750**	**$177,610**	**$2,214,750**	**$177,610**

Witness: Stacy H. Baker
Date: 4/5/2024

Question:

74. Refer to pages 74 and 75 of Mr. Warriner's direct testimony on the Gas Scada and the Tracking and Traceability projects. Please:

a. Provide the capital expenditures for each project by year from inception to completion along with the annual O&M expense and the forecasted on-going annual O&M expense post implementation in Excel.

b. Provide a copy of the cost benefit analysis in Excel with formulas intact and supporting data and assumptions explained.

c. Provide the phases of project development for each project with the related timeline and cost for each phase. Identify the phase of development that the project is currently in.

d. For the Tracking and Traceability project, explain how the information is currently tracked and captured, and why that process cannot be improved to avoid incurring the cost of a new system.

Response:

a. Please see attachment U21490-AG-CE-0221-Baker_ATT_1 for the projected total Company and gas allocation capital expenditures and O&M expense from inception to completion, including the projected annual on-going maintenance for the Gas SCADA Software Solution and Tracking & Traceability projects.

b. Please see attachment U21490-AG-CE-0221-Baker_ATT_2 for a copy of the cost benefit analysis in Excel with formulas intact or the Gas SCADA Software Solution and Tracking & Traceability projects.

c. The Gas SCADA Software Solution project is currently in the execute phase. Please refer to the table below for the project timeline of the phases of the projected total Company and gas allocation costs for the Gas SCADA Software Solution project.

Gas SCADA Software Solution					
Phase	Phase Completion	Total Company Projected		Gas Allocation Projected	
		Capital	O&M	Capital	O&M
Plan	10/31/2023	$0	$792,964	$0	$792,964
Define	5/30/2024	$1,454,523	$99,684	$1,454,523	$99,684
Execution & Go Live	11/30/2025	$10,036,697	$883,250	$10,036,697	$883,250
Close	5/31/2025	$0	$245,168	$0	$245,168
Total			$11,491,220	$2,021,066	$2,021,066

The Tracking & Traceability project is currently in the investment planning stage. Please refer to the table below for the project timeline of the phases of the projected total Company and gas allocation costs for the Tracking & Traceability project.

Tracking & Traceability					
		Total Company Projected		Gas Allocation Projected	
Phase	Phase Completion	Capital	O&M	Capital	O&M
Plan	4/1/2025	$0	$483,000	$0	$483,000
Define	9/1/2025	$1,403,490	$97,000	$1,201,500	$97,000
Execution & Go Live	4/30/2027	$13,416,100	$648,000	$12,776,700	$158,000
Close	6/30/2027	$0	$371,650	$0	$241,650
Total		**$14,819,590**	**$1,627,300**	**$14,819,590**	**$1,627,300**

d. Please refer to Company witness Lincoln D. Warriner's response.

Witness: Stacy H. Baker
Date: March 26, 2024

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Projected Total Company and Gas Allocation Capital Expenditures and O&M Expenses

From Inception to Completion

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
		Projected Total Company - Capital						**Projected Total Company - O&M**						
		Actual	**Projected**			**Projected**	**Projected**	**Actual**	**Projected**			**Projected**	**Projected**	**Projected**
Line No.	**Description**	**12 Mos Ended 12/31/2022**	**12 Mos Ending 12/31/2023**	**12 Mos Ending 12/31/2024**	**12 Mos Ending 12/31/2025**	**2026+**	**Total Project Capital Costs**	**12 Mos Ended 12/31/2022**	**12 Mos Ending 12/31/2023**	**12 Mos Ending 12/31/2024**	**12 Mos Ending 12/31/2025**	**2026+**	**Total Project O&M Costs**	**Annual Ongoing Maintenance**
1	Gas SCADA Software Solution	$ -	$ 2,512,618	$ 6,185,482	$ 2,793,100	$ -	**$ 11,491,200**	$ 631,605	$ 261,043	$ 732,920	$ 395,498	$ -	**$ 2,021,066**	$ 63,528
2	Tracking & Traceability	$ -	$ -	$ -	$ 1,771,250	$ 13,048,340	**$ 14,819,590**	$ -	$ -	$ -	$ 667,650	$ 959,650	**$ 1,627,300**	$ 67,538

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Total Company and Gas Allocation Capital Expenditures and O&M Expenses
From Inception to Completion

Attachment No.: U21490-AG-CE-0221-Baker_ATT_1
Witness: SHBaker
Date: March 2024

	(a)	(o)	(p)	(q)	(r)	(s)	(t)
		Projected Gas Allocation - Capital					
		Actual	**Projected**			**Projected**	**Projected**
Line No.	**Description**	**12 Mos Ended 12/31/2022**	**12 Mos Ending 12/31/2023**	**12 Mos Ending 12/31/2024**	**12 Mos Ending 12/31/2025**	**2026+**	**Total Project Capital Costs**
1	Gas SCADA Software Solution	$ -	$ 2,512,618	$ 6,185,482	$ 2,793,100	$ -	**$ 11,491,200**
2	Tracking & Traceability	$ -	$ -	$ -	$ 1,771,250	$ 13,048,340	**$ 14,819,590**

	(a)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)
		Projected Gas Allocation - O&M						
		Actual	**Projected**			**Projected**	**Projected**	**Projected**
Line No.	**Description**	**12 Mos Ended 12/31/2022**	**12 Mos Ending 12/31/2023**	**12 Mos Ending 12/31/2024**	**12 Mos Ending 12/31/2025**	**2026+**	**Total Project O&M Costs**	**Annual Ongoing Maintenance**
1	Gas SCADA Software Solution	$ 631,605	$ 261,043	$ 732,920	$ 395,498	$ -	**$ 2,021,066**	$ 63,528
2	Tracking & Traceability	$ -	$ -	$ -	$ 667,650	$ 959,650	**$ 1,627,300**	$ 67,538

U21490-AG-CE-0221-Baker_ATT_2

Tracking & Traceability

Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Year Counter	1	2	3	4	5	6	7
Life Flag	1	1	1	1	1	1	1
Remaining Expense Flag	1	1	1	1	1	1	1

FINANCIAL IMPACT MODEL

Assumptions

Factor/Variable	**Value**
PreTax Rate of Return	8.643%
Property Tax Factor	2.452%
Insurance Factor	0.080%
Discount Rate	7.500%

	NPVRR Benefit	**NPVRR Cost**	**B/C Ratio**
Overall	0	18,037,325	-1.000
Remaining	0	18,037,325	-1.000

COSTS

	NPV	**Total**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPITAL + COR			3,303,750	7,255,150	4,260,690	0	0	0	0
CAPITAL + COR *Escalated*			3,303,750	7,392,998	4,424,134	0	0	0	0
Total Investment			3,303,750	10,696,748	15,120,882	15,120,882	15,120,882	15,120,882	15,120,882
Beginning Rate Base			3,303,750	10,224,784	12,944,787	10,355,830	7,766,872	5,177,915	2,588,957
Depreciation			(471,964)	(1,704,131)	(2,588,957)	(2,588,957)	(2,588,957)	(2,588,957)	(2,588,957)
Ending Rate Base			2,831,786	8,520,653	10,355,830	7,766,872	5,177,915	2,588,957	0
Average Rate Base			3,067,768	9,372,718	11,650,309	9,061,351	6,472,394	3,883,436	1,294,479
O&M			749,650	747,650	320,000	320,000	320,000	320,000	75,000
O&M *Escalated*			749,650	761,855	332,276	338,589	345,022	351,577	83,967
Other Costs			0	0	0	0	0	0	0
Other Costs *Escalated*			0	0	0	0	0	0	0
NPVRR OVERALL COSTS									
Return Costs	$3,008,379	3,858,387	264,196	807,178	1,003,325	780,364	557,403	334,442	111,481
Depreciation Costs	$10,977,710	15,120,882	471,964	1,704,131	2,588,957	2,588,957	2,588,957	2,588,957	2,588,957
Property Tax	$1,600,378	2,197,112	81,008	262,284	370,764	370,764	370,764	370,764	370,764
Insurance	$54,499	74,820	2,759	8,932	12,626	12,626	12,626	12,626	12,626
O&M	$2,396,359	2,962,935	749,650	761,855	332,276	338,589	345,022	351,577	83,967
Other	$0	0	0	0	0	0	0	0	0
Total	$18,037,325	$24,214,137	$1,569,577	$3,544,380	$4,307,948	$4,091,300	$3,874,772	$3,658,366	$3,167,794
NPVRR REMAINING COSTS									
Return Costs	$3,008,379	3,858,387	264,196	807,178	1,003,325	780,364	557,403	334,442	111,481
Depreciation Costs	$10,977,710	15,120,882	471,964	1,704,131	2,588,957	2,588,957	2,588,957	2,588,957	2,588,957
Property Tax	$1,600,378	2,197,112	81,008	262,284	370,764	370,764	370,764	370,764	370,764
Insurance	$54,499	74,820	2,759	8,932	12,626	12,626	12,626	12,626	12,626
O&M	$2,396,359	2,962,935	749,650	761,855	332,276	338,589	345,022	351,577	83,967
Other	$0	0	0	0	0	0	0	0	0
Total	$18,037,325	$24,214,137	$1,569,577	$3,544,380	$4,307,948	$4,091,300	$3,874,772	$3,658,366	$3,167,794

BENEFITS

	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
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	0	0	0	0	0	0
Total O&M *Escalated*	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0
Other *Escalated*	0	0	0	0	0	0	0

U21490-AG-CE-0221 (Partial)
Page **1** of **1**

Question:

74. Refer to pages 74 and 75 of Mr. Warriner's direct testimony on the Gas Scada and the Tracking and Traceability projects. Please:

a. Provide the capital expenditures for each project by year from inception to completion along with the annual O&M expense and the forecasted on-going annual O&M expense post implementation in Excel.

b. Provide a copy of the cost benefit analysis in Excel with formulas intact and supporting data and assumptions explained.

c. Provide the phases of project development for each project with the related timeline and cost for each phase. Identify the phase of development that the project is currently in.

d. For the Tracking and Traceability project, explain how the information is currently tracked and captured, and why that process cannot be improved to avoid incurring the cost of a new system.

Response:

d. We currently capture attributes like size, wall thickness, and type of material. The Company's Gas Field Operations do not capture or track the latitude, longitude, or elevation of the specific components installed. The fusion information proposed for installed components is similarly not captured or tracked.

   GPS equipment will enable precise location readings of installation locations for various gas components and associated fusions. Capturing the barcode and GPS information for all installed components will enable data collection to include component attributes such as manufacturer, production lot information and the full extent of the component's information provided by the manufacturer and will enable the Company to avoid excessive excavations due to the inability to efficiently locate the affected sections of pipe and/or fittings when responding to plastic pipe or component manufacturer recalls.

   Unless additional GPS and barcoding equipment is utilized to capture accurate location and manufacturer barcode data, the Company would not be able to develop an effective Tracking & Traceability process to comply with the proposed PHMSA rule.

Witness: Lincoln D. Warriner
Date: March 26, 2024

Question:

237. Refer to Exhibit A-12, Schedule B-5.1, page 1. Please expand this schedule with actual costs for 2018 to 2023 and forecasted for 2024 and 2025, and provide it in Excel.

Response:

Please refer to attachment U21490-AG-CE-0396_Baker_ATT_1 for the expanded Exhibit A-12, Schedule B-5.1, page 1, to include actuals costs for 2018 to 2023 (page 1) and projected 2024 and 2025 (page 2) in Excel. Please note that 2018 through 2020 used a different categorization method than what is currently being used for 2021 through 2025.

Witness: Stacy H. Baker
Date: April 10, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Information Technology
Summary of Actual & Projected Gas and Common Capital Expenditures
($000)

Attachment: U21490-AG-CE-0396_ATT_1
Page: 2 of 2
Witness: SHBaker
Date: April 2024

Line No.	Description	Historical: 12 Mos Ended 12/31/2021	Historical: 12 Mos Ended 12/31/2022	Historical: 12 Mos Ending 12/31/2023	Projected: 9 Mos Ending 9/30/2024	Projected: 21 Mos Ending 9/30/2024	Projected: 12 mos. Ending 12/31/2024	Projected: 12 mos. Ending 9/30/2025	Projected: 12 mos. Ending 12/31/2025
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Corporate**	**2,297**	**2,342**	**775**	**662**	**1,611**	**883**	**973**	**1,003**
	Software	71	907	98	0	0	0	46	61
	Materials	2	0	0	0	43	0	0	0
	Labor	254	228	101	497	1,013	663	569	537
	Contractor Costs	1,797	1,167	488	31	345	41	129	158
	Overhead & Others	172	39	88	134	210	178	230	248
2	**Customer**	**4,830**	**2,054**	**1,096**	**377**	**1,740**	**503**	**1,921**	**2,394**
	Software	1	(120)	3	0	2	0	0	0
	Materials	(1)	7	9	0	0	0	55	73
	Labor	694	346	214	78	790	104	421	527
	Contractor Costs	3,632	1,482	714	247	818	330	1,113	1,375
	Overhead & Others	504	338	156	51	130	69	332	420
3	**Electric & Gas Shared**	**1,024**	**1,564**	**2,020**	**1,615**	**3,776**	**2,154**	**695**	**208**
	Software	105	136	412	82	84	110	27	0
	Materials	69	97	22	77	60	103	39	17
	Labor	247	305	403	803	1,899	1,071	370	137
	Contractor Costs	464	813	902	208	1,061	278	69	0
	Overhead & Others	139	213	281	444	673	593	189	55
4	**Gas**	**3,870**	**5,232**	**4,780**	**7,759**	**13,459**	**10,346**	**9,985**	**9,865**
	Software	(319)	125	1,626	858	1,715	1,144	1,512	1,634
	Materials	872	827	1,193	1,547	1,753	2,063	1,525	1,346
	Labor	468	397	336	2,250	4,104	3,000	2,392	2,190
	Contractor Costs	2,504	3,380	1,326	1,669	3,956	2,226	2,851	3,060
	Overhead & Others	344	504	298	1,435	1,930	1,913	1,705	1,636
5	**IT/Digital Foundation**	**15,169**	**7,758**	**12,553**	**9,295**	**22,191**	**12,393**	**9,715**	**8,822**
	Software	1,710	302	3,548	297	1,989	396	132	44
	Materials	9,541	3,793	6,245	5,132	12,110	6,842	6,659	6,598
	Labor	795	641	920	1,752	3,911	2,336	1,351	1,023
	Contractor Costs	2,666	2,576	1,420	1,064	2,621	1,418	758	538
	Overhead & Others	458	445	421	1,050	1,560	1,402	814	619
6	**Total Capital**	**27,189**	**18,950**	**21,223**	**19,709**	**42,778**	**26,278**	**23,289**	**22,293**

Capital Expenditures

Question:

138. Refer to the table on page 26 of Mr. Guinn's direct testimony on Lansing Service Center Plan costs. Please:

a. Expand this table to include actual costs from 2018 to 2023 and provide it in Excel.

b. Provide also the expanded table in subpart (a) to this interrogatory for only the portion applicable to the gas business and provide it in Excel.

Response:

a. See Excel Attachment U21490-AG-CE-0296-Guinn_ATT_1.

b. See Excel Attachment U21490-AG-CE-0296-Guinn_ATT_1.

Witness: Quentin A. Guinn
Date: April 9, 2024

MICHIGAN PUBLIC SERVICE COMMISSION U21490-AG-CE-0296_Guinn__ATT_1
Consumers Energy Company
U21490-AG-CE-0296
($000's)

Total	2018	2019	2020	2021	2022	2023
Lansing Service Center	-	31	1,856	166	572	3,279

Gas Allocation	2018	2019	2020	2021	2022	2023
Lansing Service Center	-	14	850	76	262	1,500

Location		**Total Plan Cost 2018**	**Total Plan Cost 2019**	**Total Plan Cost 2020**	**Total Plan Cost 2021**	**Total Plan Cost 2022**	**Total Plan Cost 2023**
Lansing SC	Master Planning						
	Programming					$160	$469
	Land Acquisition			$1,774			
	Engineering		$31	$82	$166	$412	$48
	Construction						$2,763
	Furnishings						
	Commissioning						
		$0	$31	$1,856	$166	$572	$3,279

Location		**Gas Plan Cost 2018**	**Gas Plan Cost 2019**	**Gas Plan Cost 2020**	**Gas Plan Cost 2021**	**Gas Plan Cost 2022**	**Gas Plan Cost 2023**
Lansing SC	Master Planning						
	Programming					$73	$214
	Land Acquisition			$812			
	Engineering		$14	$38	$76	$188	$22
	Construction						$1,264
	Furnishings						
	Commissioning						
		$0	$14	$850	$76	$262	$1,500

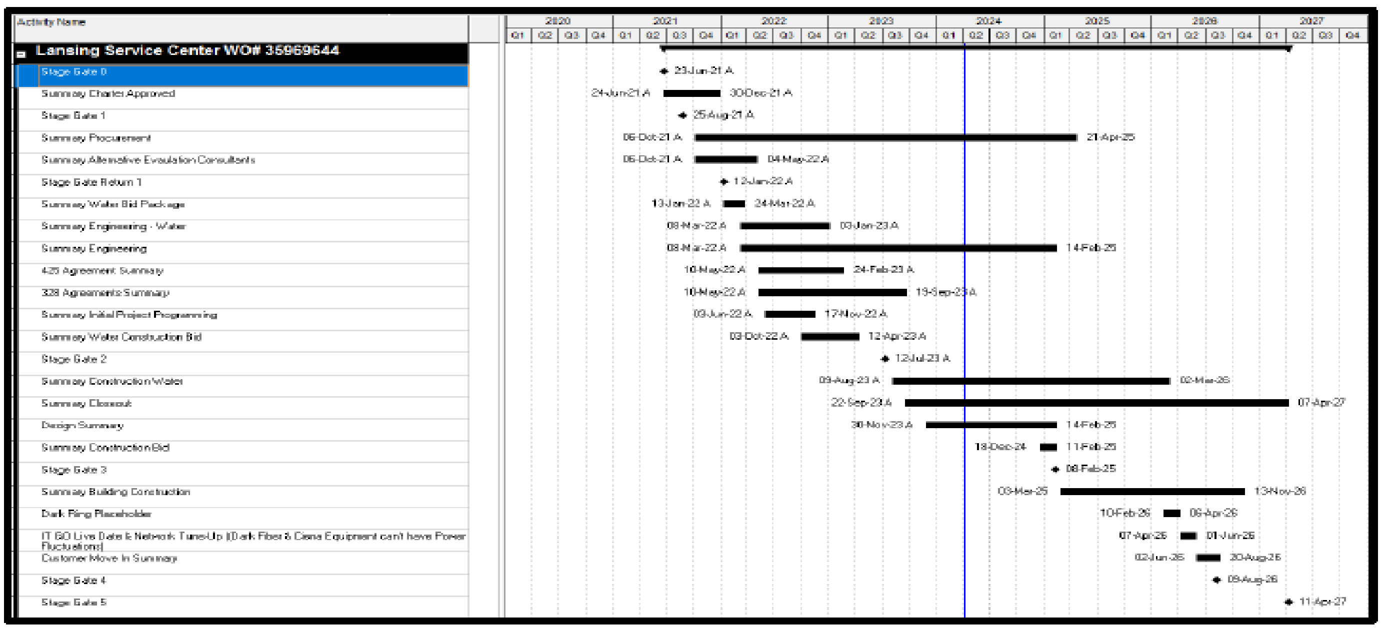
U21490-AG-CE-0297
Page **1** of **1**

Question:

139. Refer to lines 1-9 on page 27 of Mr. Guinn's direct testimony on Lansing Service Center. Please provide the most current project plan showing the completed phases of project development and each of the remaining phases with start and end dates through project completion.

Response:

The visual included shows the current project plan for the Lansing Service Center Project.



Witness: Quentin A. Guinn
Date: April 10, 2024

U21490-AG-CE-0298
Page **1** of **1**

Question:

140. Refer to lines 13-15 on page 32 of Mr. Guinn's direct testimony on the Hastings Service Center costs. Please:

a. Provide a table similar to the Lansing Service Center on page 26 expanded to include actual costs from 2018 to 2023 and provide it in Excel.

b. Provide also the expanded table in subpart (a) to this interrogatory for only the portion applicable to the gas business and provide it in Excel.

Response:

a. See excel attachment U21490-AG-CE-0298_Guinn_ATT_1.

b. See excel attachment U21490-AG-CE-0298_Guinn_ATT_1.

Witness: Quentin A. Guinn
Date: April 11, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
U21490-AG-CE-0298
($000's)

Total	2018	2019	2020	2021	2022	2023
Hastings Service Center	-	18	5	18	5	9

Gas Allocation	2018	2019	2020	2021	2022	2023
Hastings Service Center	-	8	2	8	2	4

Location		Total Plan Cost 2018	Total Plan Cost 2019	Total Plan Cost 2020	Total Plan Cost 2021	Total Plan Cost 2022	Total Plan Cost 2023
Hastings SC	Master Planning					$5	
	Programming						
	Land Acquisition		$18		$18		$9
	Engineering			$5			
	Construction						
	Furnishings						
	Commissioning						
		$0	$18	$5	$18	$5	$9

Location		Gas Plan Cost 2018	Gas Plan Cost 2019	Gas Plan Cost 2020	Gas Plan Cost 2021	Gas Plan Cost 2022	Gas Plan Cost 2023
Hastings SC	Master Planning					$2	
	Programming						
	Land Acquisition		$8		$8		$4
	Engineering			$2			
	Construction						
	Furnishings						
	Commissioning						
		$0	$8	$2	$8	$2	$4

U21490-AG-CE-0299
Page **1** of **1**

Question:

141. Refer to lines 16-22 on page 32 of Mr. Guinn's direct testimony on the Hastings Service Center. Please provide the most current project plan showing the completed phases of project development and each of the remaining phases with start and end dates through project completion.

Response:

In 2024, the Company anticipates completing acquisition of the parcel that will allow for construction of the new Hastings Service Center. The project plan for the project is therefore being revised.

Witness: Quentin A. Guinn
Date: April 10, 2024

U21490-AG-CE-0302
Page **1** of **1**

Question:

144. Refer to the table on page 40 of Mr. Guinn's direct testimony on Kalamazoo Service Center Plan costs. Please:

a. Expand this table to include actual costs from 2018 to 2023 and provide it in Excel.

b. Also provide the expanded table in subpart (a) for only the portion applicable to the gas business and provide it in Excel.

Response:

a. See excel attachment U21490-AG-CE-0302_Guinn_ATT_1.

b. See excel attachment U21490-AG-CE-0302_Guinn_ATT_1.

Witness: Quentin A. Guinn
Date: April 9, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
U21490-AG-CE-302
($000's)

	Total					
	2018	2019	2020	2021	2022	2023
Kalamazoo Service Center	57	274	2	46	334	890

	Gas Allocation					
	2018	2019	2020	2021	2022	2023
Kalamazoo Service Center	26	125	1	21	153	407

Location		Total Plan Cost 2018	Total Plan Cost 2019	Total Plan Cost 2020	Total Plan Cost 2021	Total Plan Cost 2022	Total Plan Cost 2023
Kalamazoo SC	Master Planning	$57	$274				
	Alternatives Analysis				$46		
	Programming					$334	$521
	Land Acquisition						
	Engineering			$2			$368
	Construction						
	Furnishings						
	Commissioning						
		$57	$274	$2	$46	$334	$890

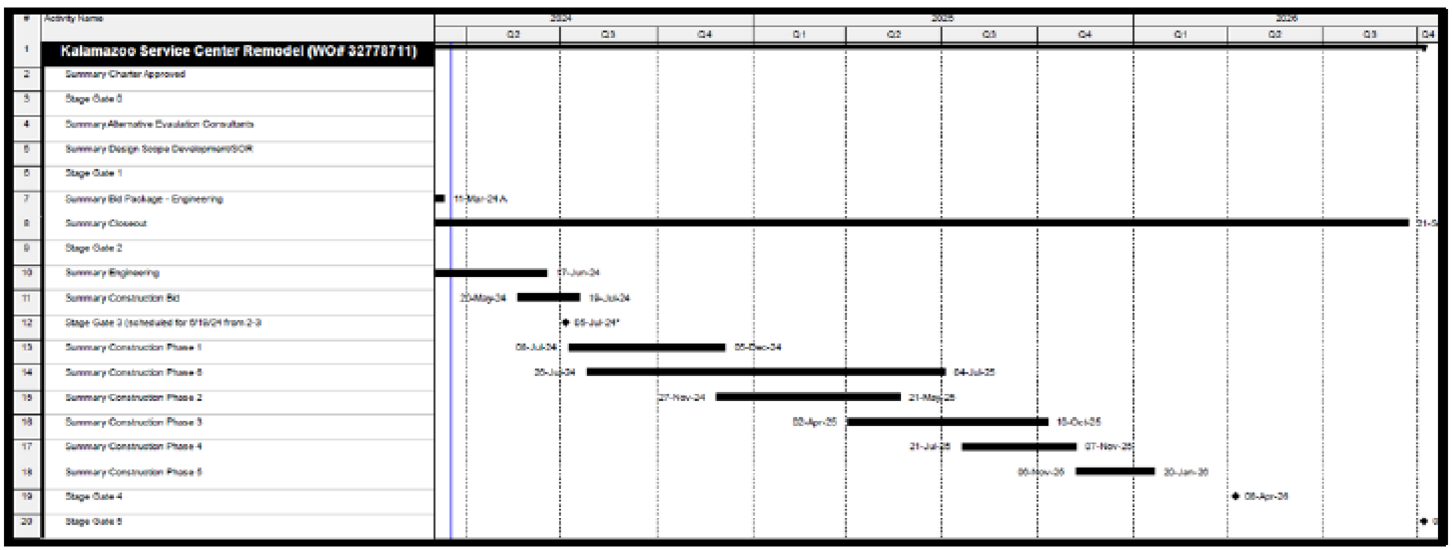
Location		Gas Plan Cost 2018	Gas Plan Cost 2019	Gas Plan Cost 2020	Gas Plan Cost 2021	Gas Plan Cost 2022	Gas Plan Cost 2023
Kalamazoo SC	Master Planning	$26	$125				
	Alternatives Analysis				$21		
	Programming					$153	$238
	Land Acquisition						
	Engineering			$1			$168
	Construction						
	Furnishings						
	Commissioning						
		$26	$125	$1	$21	$153	$407

U21490-AG-CE-0303
Page **1** of **1**

Question:

145. Refer to lines 14-19 on page 40 of Mr. Guinn's direct testimony on Kalamazoo Service Center. Please provide the most current project plan showing the completed phases of project development and each of the remaining phases with start and end dates through project completion.

Response:



Witness: Quentin A. Guinn
Date: April 9, 2024

Question:

142. Refer to lines 15-23 on page 33 of Mr. Guinn's direct testimony on the six leased facilities for the EIRP. Please:

a. Provide the term of each of the leases and the monthly lease payments for each lease.

b. Provide a reference with exhibit number, page and line number, and the amount of lease payments included in this rate case for each year or period.

c. Provide a copy of each of the lease agreements.

d. Explain why the EIRP requires this storage space now given that the EIRP has been in existence for nearly 10 years without requiring this storage space.

Response:

a. See excel attachment U21490-AG-CE-0300_Guinn_ATT_1.

b. See the direct testimony of Company witness James P. Pnacek, Jr., Exhibit A-103 (JPP-3), Line 9.

c. See Confidential attachments: U21490-AG-CE-0300_Guinn_ATT_2 CONF through U21490-AG-CE-0300_Guinn_ATT_8 CONF.

d. As regards the language in line 20 on page 33 of Mr. Guinn's direct testimony, the equipment, vehicles, and other assets referenced are staged for use in EIRP construction at these facilities.

Witness: Quentin A. Guinn
Date: April 9, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
U21490-AG-CE-0300

Location	Address	Lease Term Start	Lease Term End	Lease Payment
Holly Gas Construction	4100 East Baldwin Road, Grand Blanc, MI 48139	3/7/2022	3/6/2027	$17,436.75 (Monthly)
Jolly Road Construction	1500 East Jolly Road, Lansing, MI 48910	N/A. Consumers Energy Owned	N/A. Consumers Energy Owned	N/A. Consumers Energy Owned
Midland Gas Construction	1850 Bay City Road, Midland, MI 48642	11/9/2022	10/31/2027	$12,900 (Monthly)
Madison Heights Gas Construction	111 East 12 Mile Road, Madison Heights, MI 48071	7/1/2022	6/30/2025	(Monthly Yr. 2); $64,879.33 (Monthly Yr. 3)
Macomb Gas Construction	27432 Groesbeck Highway, Roseville, MI 48066	3/1/2023	2/28/2026	$7,500 (Monthly Yr. 1); $7,725 (Monthly Yr. 2); $7,956.75 (Monthly Yr. 3)
Saginaw Gas Construction	2119 River Street, Saginaw, MI 48601	7/1/2023	6/30/2026	$1,500 (Monthly)

U21490-AG-CE-0301
Page **1** of **1**

Question:

143. Refer to page 34 of Mr. Guinn's direct testimony on the six leased facilities for the EIRP. Please:

a. Identify and explain what the $1,421,000 in 2022 and $4,499,000 in 2023 were spent on by component.

b. If the amounts in subpart (a) include lease payments, explain why leased payments are included in capital expenditures instead of O&M expense.

c. Explain what construction work is being done at each facility and why no construction dollars are forecasted for 2024 when the construction and renovation schedule spans into mid-2024 for all of the facilities.

Response:

a. See excel attachment U21490-AG-CE-0301_Guinn_ATT_1.

b. The amounts in subpart (b) do not include lease payments.

c. See excel attachment U21490-AG-CE-0301_Guinn_ATT_1. Construction dollars are forecasted for 2024.

Witness: Quentin A. Guinn
Date: April 11, 2024

MICHIGAN PUBLIC SERVICE COMMISSION					
Consumers Energy Company					
U21490-AG-CE-0301					
($000's)					
					Filed Plan
Project	**Component**	**Construction Work Being Done**	**2022**	**2023**	**Total**
	Programming		$18,399	$21,275	$39,674
	Construction	Installation of automatic external defibrillators, fire extinguishers, first aid kits, IT systems required for network connectivity, card readers, security cameras, HVAC and plumbing upgrades, and improvements to site areas (i.e. paving, fencing, etc. for use with heavy utility equipment)	$220,601	$1,070,509	$1,291,110
	Engineering		$27,000	$5,000	$32,000
Madison Heights Gas Construction			**$266,000**	**$1,096,784**	**$1,362,783**
	Programming		$35,722	$55,258	$90,980
	Construction	Installation of automatic external defibrillators, fire extinguishers, first aid kits, IT systems required for network connectivity, card readers, security cameras, HVAC and plumbing upgrades, and improvements to site areas (i.e. paving, fencing, etc. for use with heavy utility equipment)	$402,530	$1,507,726	$1,910,256
	Engineering		$91,528	$31,252	$122,780
Holly Gas Construction			**$529,780**	**$1,594,237**	**$2,124,017**
	Programming		$13,936	$34,499	$48,435
	Construction	Installation of automatic external defibrillators, fire extinguishers, first aid kits, IT systems required for network connectivity, card readers, security cameras, HVAC and plumbing upgrades, and improvements to site areas (i.e. paving, fencing, etc. for use with heavy utility equipment)	$22,993	$1,042,771	$1,065,764
	Engineering		$61,375	$87,525	$148,900
Jolly Road Construction			**$98,304**	**$1,164,794**	**$1,263,099**
	Programming		$99,141	$84,212	$183,353
	Construction	Installation of automatic external defibrillators, fire extinguishers, first aid kits, IT systems required for network connectivity, card readers, security cameras, HVAC and plumbing upgrades, and improvements to site areas (i.e. paving, fencing, etc. for use with heavy utility equipment)	$422,710	$234,926	$657,636
	Engineering		$5,000	$28,600	$33,600
Midland Gas Construction			**$526,851**	**$347,738**	**$874,589**
	Programming			$7,254	$7,254
	Construction	Installation of automatic external defibrillators, fire extinguishers, first aid kits, IT systems required for network connectivity, card readers, security cameras, HVAC and plumbing upgrades, and improvements to site areas (i.e. paving, fencing, etc. for use with heavy utility equipment)		$29,908	$29,908
Macomb Gas Construction			**$0**	**$37,161**	**$37,161**
	Programming			$497	$497
	Construction	Installation of automatic external defibrillators, fire extinguishers, first aid kits, IT systems required for network connectivity, card readers, security cameras, HVAC and plumbing upgrades, and improvements to site areas (i.e. paving, fencing, etc. for use with heavy utility equipment)		$257,790	$257,790
Saginaw Gas Construction			**$0**	**$258,287**	**$258,287**
			$1,420,935	**$4,499,000**	**$5,919,935**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
U21490-AG-CE-0301
($000's)

Project	Actual 2022	Actual 2023	Forecast 2024	Total 2023 / 2024
Madison Heights Gas Construction	$266,000	$1,081,774	$15,010	$1,096,784
Holly Gas Construction	$529,780	$1,344,027	$250,210	$1,594,237
Jolly Road Construction	$98,304	$547,054	$617,741	$1,164,794
Midland Gas Construction	$526,851	$347,738		$347,738
Macomb Gas Construction		$37,161		$37,161
Saginaw Gas Construction		$107,887	$150,400	$258,287
	$1,420,935	$3,465,639	$1,033,361	$4,499,000

Question:

149. Refer to Exhibit A-71. Please:

a. Expand this schedule to show actual costs for each project for each year 2018 to 2023 and forecasted for calendar years 2024 and 2025 and provide in Excel.

b. Identify specifically what the $178,000 in 2023 and $138,000 in the projected test year for EV infrastructure were spent on or will be spent on.

Response:

a. See Excel Attachment U21490-AG-CE-307-Revised_Guinn_ATT_1.

b. The $178,000 in 2023 is for EV charging stations and associated electrical infrastructure work at various Consumers Energy sites including Saginaw, Flint, Owosso, Lansing, Royal Oak, Adrian, and the Meter Technology Center. The $138,000 in the projected test year is for additional EV charging stations and associated electrical infrastructure work.

Witness: Quentin A. Guinn
Date: April 18, 2024

Michigan Public Service Commission												Case No:	U-21490
Consumers Energy Company												Exhibit No:	A-71 (QAG-3)
Detailed List of Projected Gas Capital Expenditures												Page:	1 of 1
Operations Support												Witness:	QAGuinn
(000's)												Date:	December 2023
		Historical Year	Historical Year	Historical Year	Historical Year	Historical Year	Historical Year	Forecasted	Forecasted	Projected Bridge Period			Projected Test Year
		12 Mos Ended	12 Mos Ended	12 Mos Ended	12 Mos Ended	12 Mos Ended	12 Mos Ended	12 Mos Ended	12 Mos Ended	12 Mos Ended	9 Mos Ending	21 Mos Ending	12 Mos Ending
Line		12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025	12/31/2023	9/30/2024	9/30/2024	9/30/2025
No		Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas
1	**Other Equipment**	748	301	287	604	192	175	644	644	644	483	1,127	644
2	Wellness Equip	446	137	2	11	20	-	49	49	49	37	86	49
3	Computer Equipment	7	7	-	-	8	0	8	8	8	6	14	8
4	Print Equipment	28	-	75	15	-	-	42	42	42	31	73	42
5	Real Estate Tools & Equipment	78	-	24	49	17	-	10	10	10	7	17	10
6	Supply Chain Tools & Equipment	102	140	163	529	147	113	493	493	493	370	863	493
7	Facilities Tools	87	18	24	-	-	61	42	42	42	31	73	42
8	**Emergent Repairs**	865	2,365	1,606	2,728	1,955	733	757	1,189	1,673	439	2,113	1,008
9	Asset Preservation - Unplanned Repair	865	2,365	1,606	2,728	1,955	733	757	1,189	1,673	439	2,113	1,008
10	**Asset Replacement**	4,023	7,475	7,482	4,252	7,886	6,063	9,613	8,202	7,282	5,579	12,861	8,794
11	Statewide Paving	963	2,983	5,251	2,111	3,083	628	2,211	3,166	939	1,283	2,222	2,765
12	Statewide Roofing	283	1,538	848	846	1,915	676	2,092	2,143	968	1,214	2,182	2,122
13	Statewide Mechanical/Electrical	1,719	1,923	1,146	953	2,566	4,566	4,894	2,298	5,041	2,840	7,882	3,388
14	Statewide Elevators	391	297	11	183	22	138	301	480	196	175	371	405
15	Furniture	667	734	225	159	299	55	114	114	137	66	203	114
16	**New Construction**	-	22	860	734	10,521	5,526	2,891	12,344	7,431	2,138	9,569	8,250
17	Lansing Service Center	-	14	850	76	262	1,501	1,802	12,344	2,194	1,094	3,289	8,205
18	Hastings Service Center	-	8	2	8	2	4	114	-	229	69	298	45
19	Gas City Training	-	-	8	649	8,836	471	26	-	508	26	534	-
20	EIRP GCON	-	-	-	-	1,421	3,550	949	-	4,499	949	5,448	-
21	**Renovations**	26	132	100	164	2,777	1,154	3,484	8,516	1,495	2,066	3,561	6,503
22	Kalamazoo Service Center	26	125	1	21	153	407	3,328	8,287	601	2,021	2,622	6,340
23	Parnall Renovations (P1-3)	-	6	99	143	2,286	353	3	-	332	3	334	-
24	Jackson Dispatch	-	-	-	-	246	302	140	-	385	34	419	25
25	Midland Building	-	-	-	-	72	13	-	-	-	-	-	-
26	EV Infrastructure	-				21	79	14	229	178	8	186	138
27	Other not included in A-71 (QAG-3)	8,587	4,043	4,209	5,226	1,796	2,382	-	-	3,327	-	3,327	-
28	**Total Capital**	**14,249**	**14,338**	**14,544**	**13,708**	**25,127**	**16,032**	**17,389**	**30,895**	**21,852**	**10,705**	**32,557**	**25,198**

Question:

223. Refer to Exhibit A-27. For each project of $1 million or greater, please:

a. Provide the total cost from inception to completion by year for total company and the portion applicable to the gas business in Excel. Provide both the annual O&M and capital expenditures separately.

b. Provide the phases of project development (needs assessment, project scoping, conceptual design, engineering design, contract bidding, construction, completed, etc.) for each project with timeline and related cost and the phase that the project is currently in.

Response:

a. Please refer to Attachment U21490-AG-CE-0382_Bammert_ATT_1, columns a through y, for each project of $1.0 million or greater that has not been completed, with the projected Total Company and gas allocation capital expenditures and O&M from inception to completion in Excel.

b. The cost projection for each multi-phased project was developed for the collective technical effort, and not calculated by phase. However, please refer to Attachment U21490-AG-CE-0382_Bammert_ATT_2 for estimation of each multi-phased project into cost per phase. Please refer to Attachment U21490-AG-CE-0382_Bammert_ATT_1, column z, for the current project phase in 2024.

Witness: BRADLEY S. BAMMERT
Date: April 10, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Total Company and Gas Allocation Capital Expenditures and O&M Expenses
From Inception to Completion

part a

		Projected Total Company - Capital						Projected Total Company - O&M					
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
		Actual	Actual	Projected			Projected	Actual	Actual	Projected			Projected
Line No.	Description	12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	12 Mos Ending 12/31/2025	2026+	Total Project Capital Costs	12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	12 Mos Ending 12/31/2025	2026+	Total Project Capital Costs
1	Badge Reader/Lock and Key Management	$ -	$ -	$ 2,500,000	$ 2,500,000	$ 5,000,000	**$ 10,000,000**	$ 9,973	$ -	$ 143,000	$ 143,000	$ 386,000	**$ 681,973**
2	TSA Critical Facility Structure	$ -	$ 1,643,963	$ 4,000,000	$ 2,000,000	$ -	**$ 7,643,963**	$ -	$ 33,409	$ 100,000	$ 100,000	$ -	**$ 233,409**
3	Saviynt EIGA Implementation	$ -	$ -	$ 3,600,000	$ 2,500,000	$ -	**$ 6,100,000**	$ -	$ -	$ 200,000	$ 450,000	$ -	**$ 650,000**
4	Security Threat Intelligent Tool	$ -	$ -	$ -	$ 2,520,000	$ -	**$ 2,520,000**	$ -	$ -	$ -	$ 20,000	$ -	**$ 20,000**
5	Physical Security - Asset Refresh	$ -	$ -	$ 1,549,528	$ -	$ -	**$ 1,549,528**	$ -	$ -	$ 10,000	$ -	$ -	**$ 10,000**
6	Physical Security - Asset Refresh	$ -	$ -	$ -	$ 1,600,000	$ -	**$ 1,600,000**	$ -	$ -	$ -	$ 10,000	$ -	**$ 10,000**
7	Enhancements - O&M	$ -	$ -	$ -	$ -	$ -	**$ -**	$ -	$ -	$ -	$ 598,316	$ -	**$ 598,316**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Total Company and Gas Allocation Capital Expenditures and O&M Expenses
From Inception to Completion

Attachment No.: U21490-AG-CE-0382_ATT_1
Witness: BSBammert
Date: April 2024

	(a)	(n)	(o)	(p)	(q)	(r)	(s)
		Projected Gas Allocation - Capital					
		Actual	Actual	Projected			Projected
Line No.	Description	12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	12 Mos Ending 12/31/2025	2026+	Total Project Capital Costs
1	Badge Reader/Lock and Key Management	$ -	$ -	$ 758,750	$ 758,750	$ 1,517,500	**$ 3,035,000**
2	TSA Critical Facility Structure	$ -	$ 722,029	$ 1,855,600	$ 927,800	$ -	**$ 3,505,429**
3	Saviynt EIGA Implementation	$ -	$ -	$ 1,092,600	$ 758,750	$ -	**$ 1,851,350**
4	Security Threat Intelligent Tool	$ -	$ -	$ -	$ 764,820	$ -	**$ 764,820**
5	Physical Security - Asset Refresh	$ -	$ -	$ 470,282	$ -	$ -	**$ 470,282**
6	Physical Security - Asset Refresh	$ -	$ -	$ -	$ 485,600	$ -	**$ 485,600**
7	Enhancements - O&M	$ -	$ -	$ -	$ -	$ -	**$ -**

	(a)	(t)	(u)	(v)	(w)	(x)	(y)	(z)
		Projected Gas Allocation - O&M						part b
		Actual	Actual	Projected			Projected	
Line No.	Description	12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	12 Mos Ending 12/31/2025	2026+	Total Project Capital Costs	Current Phase in 2024
1	Badge Reader/Lock and Key Management	$ 3,491	$ -	$ 52,910	$ 52,910	$ 142,820	**$ 252,131**	Plan
2	TSA Critical Facility Structure	$ -	$ 11,693	$ 37,000	$ 37,000	$ -	**$ 85,693**	Execute
3	Saviynt EIGA Implementation	$ -	$ -	$ 74,000	$ 166,500	$ -	**$ 240,500**	Investment Planning
4	Security Threat Intelligent Tool	$ -	$ -	$ -	$ 7,400	$ -	**$ 7,400**	Investment Planning
5	Physical Security - Asset Refresh	$ -	$ -	$ 3,700	$ -	$ -	**$ 3,700**	N/A
6	Physical Security - Asset Refresh	$ -	$ -	$ -	$ 3,700	$ -	**$ 3,700**	N/A
7	Enhancements - O&M	$ -	$ -	$ -	$ 221,377	$ -	**$ 221,377**	N/A

MICHIGAN PUBLIC SERVICE COMMISSION				Attachment No:	U21490-AG-CE-0382_ATT_2	
Consumers Energy Company				Page:	Page 1 of 4	
				Witness:	BSBammert	
Badge Reader/Lock and Key Management				Date:	April 2024	

Phase	Phase Completion	Total Company Projected		Gas Allocation Projected	
		Capital	O&M	Capital	O&M
Plan	5/31/2024	$ -	$ 125,532	$ -	$ 46,248
Define	7/31/2024	$ 1,250,000	$ 143,000	$ 379,375	$ 52,910
Execution & Go-Live	11/1/2027	$ 8,750,000	$ 170,441	$ 2,655,625	$ 63,063
Close	11/30/2027	$ -	$ 243,000	$ -	$ 89,910
Total		**$ 10,000,000**	**$ 681,973**	**$ 3,035,000**	**$ 252,131**

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Attachment No: U21490-AG-CE-0382_ATT_2
Page: Page 3 of 4
Witness: BSBammert
Date: April 2024

Saviynt EIGA Implementation

Phase	Phase Completion	Total Company Projected Capital	Total Company Projected O&M	Gas Allocation Projected Capital	Gas Allocation Projected O&M
Plan	4/5/2024	$ -	$ 50,000	$ -	$ 18,500
Define	6/15/2024	$ 2,500,000	$ 50,000	$ 758,750	$ 18,500
Execution & Go-Live	10/31/2025	$ 3,600,000	$ 50,000	$ 1,092,600	$ 18,500
Close	11/30/2025	$ -	$ 500,000	$ -	$ 185,000
Total		**$ 6,100,000**	**$ 650,000**	**$ 1,851,350**	**$ 240,500**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Exhibit AG-39
Case No. U-21490
April 22, 2024
Page 1 of 1

Adjustments to Capital Expenditures, Working Capital and Rate Base

Line	Description	Capital Expenditure Reductions [1] 2022 & Prior	2023	9 M/E Sep 2024	12 M/E Sep 2025	Total	Rate Base Reduction	Depreciation Rate [2]	Reduction in Depreciation Expense	Property taxes [3] Rate	Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)		
1	**Distribution Plant:**										
2	MAOP Projects		1,544	6,968	35,751	44,263	26,388	2.54%	$ 670	$ 0.0138620	$ 307
3	Cathodic Protection			1,146	1,646	2,792	1,969	2.54%	50	$ 0.0138620	19
4	Capacity/Augmentation Projects			2,222	3,996	6,218	4,220	2.54%	107	$ 0.0138620	43
5	Material Condition/EIRP			17,943	45,344	63,287	40,615	2.54%	1,032	$ 0.0138620	439
6	Material Condition Non-Modeled MAOP			2,750	4,925	7,675	5,213	2.54%	132	$ 0.0138620	53
7	VSR Program			4,795	15,551	20,346	12,571	2.54%	319	$ 0.0138620	141
8	Advanced Methane Detection Project	$ 7,035		1,539	4,772	13,346	10,960	2.54%	278	$ 0.0138620	93
9	Material Condition Program-2023 Underspent		17,000			17,000	17,000	2.54%	432	$ 0.0138620	118
10	**Transmission Plant**										
11	MAOP Projects	306	2,638	239	2,884	6,067	4,625	2.30%	106	$ 0.0138620	42
12	Deliverability Field Measurement				9,425	9,425	4,713	2.30%	108	$ 0.0138620	65
13	Deliverability Base Pipeline				7,753	7,753	3,877	2.30%	89	$ 0.0138620	54
14	Regulator Stations-Distribution			2,801	8,433	11,234	7,018	2.30%	161	$ 0.0138620	78
15	T$S City Gate Stations			416	10,138	10,554	5,485	2.30%	126	$ 0.0138620	73
16	PLD Projects				3,149	3,149	1,575	2.30%	36	$ 0.0138620	22
17	**Gas Storage & Compression**										
18	Overisel Compressor Station			5,787	4,991	10,778	8,283	2.49%	206	$ 0.0138620	75
19	Muskegon Compressor Station			3,007	15,185	18,192	10,600	2.49%	264	$ 0.0138620	126
20	Northville Compressor Station			1,432	4,936	6,368	3,900	2.49%	97	$ 0.0138620	44
21	St. Clair Compressor Station			1,959	2,925	4,884	3,422	2.49%	85	$ 0.0138620	34
22	Riverside Storage Field Retirement			33,318	37,067	70,385	51,852	2.49%	1,291	$ 0.0138620	488
23	Northville - Lyon 29/34 Dehydration Facility		1,373	9,273	22,191	32,837	21,742	2.49%	541	$ 0.0138620	228
24	Well Rehabilitation Program			3,289	1,326	4,615	3,952	2.49%	98	$ 0.0138620	32
25	Gas Compression & Storage 2022 Underspent		9,229			9,229	9,229	2.49%	230	$ 0.0138620	64
26	**Information Technology**										
27	Projects in Planning Phase				1,020	1,020	510	20.00%	102	$ 0.0138620	7
28	Customer Work Request Web Portal				349	349	175	20.00%	35	$ 0.0138620	2
29	Gas Compression Historian system				1,329	1,329	665	20.00%	133	$ 0.0138620	9
30	Facilities Tracking and Traceability system				1,328	1,328	664	20.00%	133	$ 0.0138620	9
31	IT Capital Expenditures 2023 Underspent		1,846			1,846	1,846	20.00%	369	$ 0.0138620	13
32	**Operations Support**										
33	Service Centers			3,335	9,266	12,601	7,968	2.68%	214	$ 0.0138620	87
34	EIRP Support Facilities	1,421	4,499			5,920	5,920	2.68%	159	$ 0.0138620	41
35	Facilities 2023 Underspent		1,321			1,321	1,321	2.68%	35	$ 0.0138620	9
36	**Security**										
37	Projects in Planning Phase	-	-	1,388	2,174	3,562	2,475	20.00%	495	$ 0.0138620	25
38	**Total**	$ 8,762	$ 39,450	$ 103,607	$ 257,854	$ 409,673	$ 280,746		$ 8,136		$ 2,839
39											
40	**Working Capital Adjustments**						104,600				
41											
42	**Total Rate Base Reduction**						$ 385,346				

Source: (1) AG witness Coppola Direct Testimony and related exhibits.
(2) Depreciation rates from Company workpaper WP-HLR-22 for 2024 and 2025 rates.
(3) The property tax adjustment is calculated based on 50% of the disallowed capital expenditures x the property tax rate calculated by the Company on line 16 of Exhibit A-114 (BJV-1), page 1.

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21490**
Consumers Energy Gas Rate Case | **Exhibit AG-40**
April 22, 2024
Working Capital - Summary | **Page 1 of 1**

Line	Description (a)		Millions Of Dollars (b)	Note or Ref. (c)
1	Test Year Working Capital Per Company		$ 1,514.7	1
	Attorney General Changes			
2	Gas Storage Inventory Reduction - Lower Gas Prices		(66.7)	2
3	Reduced Accounts Payable - Lower Gas Prices		11.4	3
	Accounts Receivable Reduction - Reduced Revenues		(30.1)	Exh. AG-41
4	Income Taxes Accrued		(19.2)	4
5	**Total Change**	(Sum of L2 to L4)	**$ (104.6)**	
6	**AG Revised Working Capital Level**	(L1 + L5)	**$ 1,410.1**	
7	**Change in Working Capital**	**(L6 less L1)**	**$ (104.6)**	

1 Per Company Exhibit A-12, Schedule B4
2 Determined as follows

Gas in storage per Exhibit A-12, Schedule B4	$ 463.5
Revised cost of Gas in Storage per DR-SA-CE-101 Attachment 1	396.8
Reduction in Inventory & Working Capital	$ 66.7

3 Reflects 17.07% of the change in gas storage inventory due to lower gas prices (see Company WP-HLR 26 for this percentage)
4 Reflects Use of Historical Average for the 13 month period June 2023 per Exhibit A-13 (HLR-34) Sched. B-4
which results in elimination of adjustment in column (i) of this exhibit.

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21490**
Consumers Energy Gas Rate Case | **Exhibit AG-41**
April 22, 2024
Working Capital - Accounts Receivable | **Page 1 of 1**

Line	Description	Revenues	Accounts Receivable	Notes
		Millions of Dollars		
	(a)	(b)	(c)	(d)
1	Historical 2022 Revenues and Accounts Receivable	$ 2,715.5	$ 139.0	Note 1 Below
2	Projected Revenues per Company	2,398.0		Ex. A-13 (HLR-36), Line 4
3	Reduction in Revenues per Company Case	$ 317.5		L1 less L2
4	Additional Revenue Reduction - Lower Cost of Gas	148.0		Note 2 Below
5	Total Reduction in Revenues	$ 465.5		L3 + L4
6	Percentage Reduction in Revenues	17.14%	17.14%	L 5 / L 1 (Col b)
7	**Reduction in Accounts Receivable (vs. 2022 level)**		**23.8**	L 1 x L 6 (Col c)
8	Accounts Receivable Level per AG Case		**$ 115.2**	L 1 less L 7
9	Projected Test Year Accounts Receivable		**145.3**	Ex. A-12 (HLR-34), Line 4
10	**Change in Accounts Receivable and Working Capital**		**$ (30.1)**	L 8 less L 9

Notes
1 Revenues from Exhibit A-3 (HLR--9), Sch. C-1, Line 4 and Accounts Receivable from Exhibit A-2 (HLR-6), Sch. B-4, line 2
2 Reduction in Revenues Due to a Lower Cost of Gas

Cost of Gas Rate per Company Case (see Exhibit A-83 (TKJ-4)	$ 3.864
Less Cost of Gas Rate Revised by Company (see DR SA-CE-102, Att. 1 line 34)	3.197
Cost per MCF Reduction	$ 0.667
Percentage change in Cost of Gas Rate	17.26%
Cost of Gas per Company (see Exhibit A-13 (HLR-40) Sch. C-4	857.4
Cost of Gas Reduction (multiply) to Line 4 Above	$ 148.0

U21490-SA-CE-101
Requested By: Nora Quilico (NBQ-1 - 1)
Respondent: Timothy K. Joyce
Date of Response: 2/19/2024
Page **1** of **1**

Question:

1. Referring to Company witness Timothy Joyce's testimony pg-20 and Exhibit A-85 (TJK-7), please update the 13-month average cost of gas in storage through September 2025, which was submitted as $3.571/Mcf ($463,500,225/129,781,253 Mcf) at the time of filing. Utilize the most current NYMEX futures pricing, and any other more up-to-date relevant data available. Provide NYMEX data used, and all relevant Excel spreadsheets used to calculate the updated 13-month average cost of gas in storage.

Response:

Please see attachment U21490-SA-CE-0101-Joyce_ATT_1.xlsx for the updated projected test year 13-month average cost of gas in storage of $3.032/Mcf ($396,819,352/130,864,968). This update includes Accounting booked actuals and updated NYMEX pricing.

Please see attachment U21490-SA-CE-0101-Joyce_ATT_2.xlsx for updated NYMEX pricing as of the first 5 trading days in February 2024.

U21490-SA-CE-101-Joyce_ATT_1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Storage Fields Month End Summary
September 2022 - January 2024 Historical / February 2024 - September 2025 Forecast
Updated NYMEX Settled Days February 1-7, 2024
VOLUMES @ 14.65 PSIA DRY

Case No.: U-21490
~~Exhibit No.: A-85 (TKJ-7)~~
Page: 1 of 1
Witness: TKJoyce
~~Date: December 2023~~

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line			GCR			GCC			COMBINED		
No.	MONTH		VOL - MMCF	$000	$ / MCF	VOL - MMCF	$000	$ / MCF	VOL - MMCF	$000	$ / MCF
1	Sep-22	Booked	164,348	965,442	5.874	8,617	68,018	7.893	172,965	1,033,460	5.975
2	Oct-22	Booked	165,351	970,566	5.870	10,604	84,398	7.959	175,955	1,054,964	5.996
3	Nov-22	Booked	152,020	892,244	5.869	11,411	90,572	7.937	163,431	982,816	6.014
4	Dec-22	Booked	129,046	757,417	5.869	10,254	82,043	8.001	139,300	839,460	6.026
5	Jan-23	Booked	111,151	652,384	5.869	8,261	66,097	8.001	119,412	718,480	6.017
6	Feb-23	Booked	89,500	525,294	5.869	5,503	44,030	8.001	95,003	569,324	5.993
7	Mar-23	Booked	70,606	414,384	5.869	2,860	22,882	8.001	73,466	437,266	5.952
8	Apr-23	Booked	83,376	441,863	5.300	-359	-2,875	8.001	83,017	438,988	5.288
9	May-23	Booked	101,620	481,786	4.741	295	994	3.369	101,915	482,780	4.737
10	Jun-23	Booked	122,686	527,609	4.300	2,133	11,902	5.581	124,819	539,511	4.322
11	Jul-23	Booked	141,154	573,942	4.066	4,445	25,331	5.699	145,598	599,273	4.116
12	Aug-23	Booked	155,223	607,731	3.915	6,846	39,132	5.716	162,068	646,863	3.991
13	Sep-23	Booked	169,314	642,225	3.793	9,136	52,227	5.717	178,450	694,452	3.892
14	13 Month Avg		127,338	650,222	5.106	6,154	44,981	7.309	133,492	695,203	5.208
15	Sep-23	Booked	169,314	642,225	3.793	9,136	52,227	5.717	178,450	694,452	3.892
16	Oct-23	Booked	167,820	634,482	3.781	11,223	64,119	5.713	179,043	698,601	3.902
17	Nov-23	Booked	152,490	577,204	3.785	12,042	68,861	5.719	164,532	646,066	3.927
18	Dec-23	Booked	137,248	519,505	3.785	11,283	64,524	5.719	148,531	584,028	3.932
19	Jan-24	Booked	110,429	417,990	3.785	9,442	53,994	5.719	119,871	471,984	3.937
20	Feb-24	Forecast	85,552	323,826	3.785	5,896	33,718	5.719	91,448	357,544	3.910
21	Mar-24	Forecast	76,281	288,732	3.785	3,053	17,462	5.719	79,334	306,194	3.860
22	Apr-24	Forecast	86,906	311,209	3.581	-365	-1,490	4.081	86,541	309,719	3.579
23	May-24	Forecast	97,171	333,055	3.428	540	2,205	4.081	97,712	335,260	3.431
24	Jun-24	Forecast	113,994	370,586	3.251	2,347	9,580	4.081	116,341	380,166	3.268
25	Jul-24	Forecast	132,392	413,927	3.127	4,584	18,711	4.081	136,976	432,637	3.158
26	Aug-24	Forecast	151,309	459,219	3.035	6,914	28,218	4.081	158,223	487,437	3.081
27	Sep-24	Forecast	164,316	488,897	2.975	9,109	37,175	4.081	173,425	526,072	3.033
28	13 Month Avg		126,556	444,681	3.514	6,554	34,562	5.273	133,110	479,243	3.600
29	Sep-24	Forecast	164,316	488,897	2.975	9,109	37,175	4.081	173,425	526,072	3.033
30	Oct-24	Forecast	168,516	498,353	2.957	11,084	45,239	4.081	179,600	543,592	3.027
31	Nov-24	Forecast	155,627	460,237	2.957	11,768	48,028	4.081	167,394	508,264	3.036
32	Dec-24	Forecast	133,408	394,530	2.957	10,729	43,790	4.081	144,138	438,320	3.041
33	Jan-25	Forecast	107,882	319,042	2.957	8,082	32,984	4.081	115,964	352,025	3.036
34	Feb-25	Forecast	83,434	246,740	2.957	5,064	20,669	4.081	88,498	267,409	3.022
35	Mar-25	Forecast	68,799	203,460	2.957	2,915	11,897	4.081	71,714	215,357	3.003
36	Apr-25	Forecast	78,396	232,120	2.961	-354	-1,304	3.681	78,042	230,816	2.958
37	May-25	Forecast	95,889	284,511	2.967	541	1,990	3.681	96,429	286,501	2.971
38	Jun-25	Forecast	114,085	341,034	2.989	2,320	8,541	3.681	116,405	349,575	3.003
39	Jul-25	Forecast	132,725	400,767	3.020	4,529	16,669	3.681	137,254	417,436	3.041
40	Aug-25	Forecast	151,886	462,715	3.046	6,830	25,139	3.681	158,716	487,854	3.074
41	Sep-25	Forecast	164,662	502,292	3.050	9,003	33,137	3.681	173,665	535,429	3.083
42	13 Month Avg		124,586	371,900	2.985	6,278	24,920	3.969	130,864.968	396,819.352	3.032

Question:

20. Refer to Exhibit A-12 (HLR-34), Schedule B-4, regarding the Company's Accrued Taxes.

a. Provide a schedule showing the monthly balances of Accrued Taxes for the 13 months ended December 2023.

b. The Company shows a balance of $151.3 million for Accrued Taxes on this exhibit for the projected test year which is substantially lower than the historic test year. Did the Company include the effect of
paying additional taxes as a result of the rate increase amount requested in this case in calculating Accrued Taxes? If yes, explain how the additional Accrued Taxes were calculated and where they are shown.

Response:

a. Please refer to the Excel file U21490-AG-CE-0155_Vanblarcum_ATT_1. Please note that allocations are preliminary and subject to change after filing of the MPSC P-521/P-522 report.

b. No, the Company's computation of accrued income taxes for the projected test year does not include additional income from rate relief requested in this case.

Witness: Brian J. Vanblarcum
Date: March 12, 2024

Consumers Energy Company
Monthly Accrued Tax Balances
For the 13-Months Ended December 2023
U21490-AG-CE-0155_VanBlarcum_Attachment 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Line No.	SAP Account	FERC Account	Account Description	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	13-Mo Ended Dec-23
1	2300000	236.1000	Accrued Federal Income Tax Payable	(326,562.71)	(3,819,609.50)	1,050,523.04	7,886,918.07	14,521,636.07	14,072,874.86	40,987,495.99	33,010,083.60	31,252,616.94	36,941,495.38	24,581,812.33	15,771,986.87	10,466,348.54	17,415,201.50
2	2300500	236.1000	Accrued Income Tax Payable - APB 28	(0.04)	575,532.15	(1,442,239.42)	(2,821,416.54)	(4,090,244.36)	(3,589,195.23)	(2,682,074.34)	(1,269,416.97)	(2,755,917.76)	(2,019,952.84)	(2,101,134.72)	(1,462,722.89)	(0.04)	(1,819,906.38)
3	2301000	236.1000	Accrued State Income Tax	(2,476,869.39)	(3,063,798.96)	(1,785,087.43)	(130,274.56)	203,276.55	240,632.60	7,036,235.87	5,224,933.73	4,981,786.54	6,605,454.96	7,941,364.60	5,330,033.40	3,226,679.09	2,564,182.08
4	2301200	236.1000	Accrued SBT Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2301400	236.1000	Accrued Franchise Tax	-	-	-	-	193.60	193.60	193.60	193.60	193.60	193.60	100.00	100.00	100.00	112.43
6	2301500	236.1000	Accrued State Income Tax Payable - APB 28	-	(35,703.49)	222,251.76	232,672.95	372,747.66	59,163.28	141,440.45	(63,179.14)	29,894.76	(581,455.91)	(650,841.02)	(773,187.59)	-	(80,476.64)
7	2301600	236.1000	Accrued Local Income Tax Payable	(82,796.86)	(99,126.34)	(78,228.45)	(45,149.68)	(8,880.69)	(20,440.38)	187,957.98	119,401.31	98,469.54	136,983.23	221,739.88	117,843.53	45,158.74	45,610.14
8	2301700	236.1000	Accrued Local Income Tax Payable - APB 28	-	(1,736.97)	9,897.45	8,011.85	11,498.64	3,827.34	(5,731.48)	(5,283.49)	10,495.86	24,642.49	43,566.70	51,358.56	-	11,580.53
9	2301800	236.1000	Accrued Federal Excise Tax Payable	(52.84)	(30.00)	(24.71)	(27.18)	(16.71)	(30.21)	(23.43)	(48.69)	(57.02)	(58.14)	(128.15)	(56.53)	(42.93)	(45.89)
10	2301900	236.1000	Accrued Michigan CNG Fuel Tax Payable	(115.85)	(86.97)	(37.10)	(40.86)	(24.87)	(45.42)	(35.04)	(54.98)	(86.26)	(90.67)	(109.50)	(88.20)	(67.42)	(67.93)
11	2304600	236.1000	Accrued Sales & Use Tax Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2305000	236.1000	Accrued Real & Personal Property Taxes	(166,824,866.94)	(166,852,676.40)	(166,890,721.11)	(166,928,594.39)	(166,969,423.10)	(166,746,863.66)	(166,772,365.90)	(143,970,819.25)	(69,296,551.58)	(67,849,512.76)	(67,868,026.34)	(67,900,815.26)	(185,201,444.36)	(136,159,437.00)
13	2305001	236.1000	RECN AP Real & Personal Property Taxes	(50,595,850.41)	-	-	-	-	-	-	-	-	-	-	-	(66,594,486.81)	(9,014,641.32)
14	2306000	236.1000	Accrued SUTA Payable	-	(37,519.72)	(3,621.35)	-	(386.20)	(789.98)	-	(263.90)	88.05	-	(222.31)	(278.67)	(105,179.30)	(11,397.95)
15	2306100	236.1000	Accrued FUTA Payable	-	(3,416.01)	(166.71)	-	(46.47)	(199.23)	-	(11.32)	(7.60)	-	(51.96)	(39.07)	(26,623.04)	(2,350.88)
16	2306200	236.1000	Accrued Employer FICA Payable	-	(312,319.89)	(555,693.63)	-	(306,953.01)	(307,197.79)	-	(364,851.73)	(435,087.95)	-	(265,465.88)	(242,389.91)	(341,054.39)	(240,847.24)
17	2306300	236.1000	Accrued Payroll Taxes	(1,797,044.28)	(1,685,113.21)	(1,273,541.12)	(1,557,648.13)	(1,225,990.75)	(1,850,252.74)	(2,432,880.88)	(1,805,925.60)	(1,383,576.24)	(1,445,950.93)	(1,271,972.97)	(1,139,798.57)	(1,139,851.59)	(1,539,195.92)
18	2306400	241.0000	Deferred Employer FICA Payable - Current	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2500000	241.0000	Employee FICA Withholding	-	(312,319.95)	(555,693.37)	-	(306,952.69)	(307,197.71)	-	(365,009.76)	(435,770.18)	-	(267,821.11)	(246,636.55)	(341,054.35)	(241,419.67)
20	2500200	241.0000	Federal Income Tax Withholding	-	(491,995.37)	(1,220,195.49)	-	(485,116.90)	(481,925.68)	-	(716,136.03)	(1,050,838.28)	-	(532,735.35)	(518,943.05)	(588,655.04)	(468,195.48)
21	2500230	241.0000	City Income Tax Withholding	-	(3,297.72)	(5,133.39)	-	(3,130.36)	(3,204.05)	-	(3,689.78)	(4,470.37)	-	(3,072.51)	(3,116.05)	(3,629.53)	(2,518.75)
22	2500240	241.0000	State Income Tax Withholding	-	(153,688.70)	(278,134.12)	-	(151,041.15)	(150,908.07)	-	(187,067.78)	(227,854.27)	-	(150,830.55)	(147,259.44)	(161,741.55)	(123,732.74)
23	2590000	241.0000	Accrued Sales Tax Payable	(4,004,479.98)	(4,564,112.92)	(2,937,502.97)	(2,481,591.28)	(1,696,080.01)	(936,248.03)	(1,350,240.82)	(2,042,050.39)	(1,527,519.35)	(1,430,687.87)	(1,092,398.36)	(1,988,425.98)	(3,374,044.89)	(2,263,490.99)
24	2590001	241.0000	Sales Tax Refunded 2004-2007	14,373.45	281,101.78	145,206.86	71,633.32	135,508.86	20,530.70	164,160.13	(73,583.85)	36,562.37	98,443.56	12,193.10	46,611.42	78,241.74	79,306.42
25	2591002	241.0000	Accrued Use Tax Payable-CV	7,065.53	7,065.53	7,065.53	7,065.53	7,065.53	7,065.53	7,065.53	7,065.53	7,065.53	7,065.53	7,065.53	7,065.53	7,065.53	7,065.53
26	2590002	241.0000	Accrued Sales Tax Payable-CV	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	2590003	241.0000	Accrued Sales Tax Payable - Manual	-	(3.23)	-	-	-	-	-	-	-	-	-	-	-	(0.25)
28	2591000	241.0000	Accrued Use Tax Payable	(43,455.05)	(136,150.60)	(135,410.14)	(122,398.25)	(87,046.55)	(276,843.28)	(71,361.40)	(114,312.85)	(42,606.83)	(191,468.80)	(77,113.86)	(68,907.10)	(34,159.96)	(107,787.28)
29	2591003	241.0000	Accrued Use Tax Payable - Manual	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	2981000	236.1000	Accrued Federal FIN 48 Liab- Non Current	1,313,398.61	1,313,398.61	1,313,398.61	1,334,732.74	1,334,732.74	1,334,732.74	755,997.25	755,997.25	755,997.25	1,393,148.78	1,393,148.78	1,897,269.61	1,897,269.61	1,291,786.35
31	2981200	236.1000	Accrued State FIN 48 Liab- Non Current	(9,249,949.47)	(9,281,402.82)	(9,262,489.68)	(9,334,586.69)	(9,340,763.71)	(9,350,558.88)	(9,268,728.30)	(9,328,280.64)	(9,346,172.11)	(9,973,034.78)	(10,030,190.14)	(9,959,588.17)	(10,022,712.60)	(9,519,112.15)
32	2981500	236.1000	Accrued Local FIN 48 Liab- Non Current	(835.20)	(835.20)	(835.20)	(835.20)	(835.20)	(835.20)	(835.20)	(835.20)	(835.20)	(835.20)	(835.20)	-	-	(706.71)
33	2983000	236.1000	Deferred Employer FICA Payable - Non Current	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34			Total Accrued Taxes - Gas Utility	(234,068,041.43)	(188,677,845.90)	(183,676,412.13)	(173,881,528.30)	(168,086,273.11)	(168,283,714.88)	(133,303,730.00)	(121,193,146.33)	(49,334,180.53)	(38,285,620.37)	(50,111,959.01)	(61,229,984.10)	(252,213,884.54)	(140,180,486.20)

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21490**
Consumers Energy - Gas Rate Case | **Exhibit AG-44**
Date: April 22, 2024

Recommended Capital Structure & Cost Rates for
Projected Year Ending September 2025 (Millions of Dollars)

Line	Description	Note	Capital Balances	% Permenant Capital	% Total Capital	Cost Rate*	Total Cost (d) x (e)	Conversion Factors**	Pre-Tax Wtd. Cost (f) x (g)
			Consumers Energy Capital Structure						
	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Long Term Debt	(A)	$ 11,695	49.84%	41.35%	4.31%	1.78%	1.0000	1.78%
2	Preferred Stock		37	0.16%	0.13%	4.50%	0.01%	1.3381	0.01%
3	Common Equity	(A)	11,732	50.00%	41.48%	9.85%	4.09%	1.3381	5.47%
4	Total Permanent Capital	(B)	23,464	100.00%	82.96%		5.87%		7.26%
5	Short Term Debt	(B)	287		1.01%	5.16%	0.05%	1.0000	0.05%
6	Deferred Income Taxes	(B)	4,416		15.61%	0.00%	0.00%	1.0000	0.00%
7	JDITC								
8	Long Term Debt	(A)	58		0.21%	4.31%	0.01%	1.0000	0.01%
9	Preferred Stock		-		0.00%	4.50%	0.00%	1.3381	0.00%
10	Common Equity	(A)	59		0.21%	9.85%	0.02%	1.3381	0.03%
11	Total JDITC	(B)	117.0						
12	**Total Capitalization & Cost Rates**		$ 28,284		100.00%		$\boxed{5.96\%}$		$\boxed{7.35\%}$

Notes

* All Cost rates per Exhibit A-14 (MRB-1), Schedule D1 except for Common Equity which is set forth on Exhibit AG-45.

** See Company Exhibit A-14 (MRB-1), Schedule D1, column (h).

(A) Reflects the permanent capital of CECo per Exhibit A-14 (MRB-1), Sched. D1, with common equity set at 50%.

(B) Capital balances per Company Exhibit A-14 (MRB-1), Schedule D1.

Summary of Cost of Common Equity Analysis

Line	Description (a)	Relative Weighting (b)	Consumers Energy Proxy Rates (c)	Note (d)
1	Discounted Cash Flow Approach (DCF)	50.00%	9.51%	1
2	Capital Asset Pricing Model Approach (CAPM)	25.00%	10.42%	2
3	Utility Equity Risk Premium Approach	25.00%	9.93%	3
4	**Calc. Cost of Common Equity (Sum of Col. (b) x (c) for Lines 1, 2 and 3)**		**9.84%**	
5	Rounding up		0.01%	
6	**Cost of Common Equtiy per AG Case (L4 + L5)**		$\boxed{\textbf{9.85\%}}$	

Note 1 See Exhibit AG-46
Note 2 See Exhibit AG-47
Note 3 See Exhibit AG-48

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21490
Exhibit AG-46
Date: April 22, 2024
Page 1 of 1

Discounted Cash Flow (DCF) Application
(See Equation Below)

Line	Company	Ticker	Average 30 Day High Low Price*	Projected 2023-24 Ann. Dividend**	Dividend Yield Col. (d)/(c)	EPS Growth Rate*** Value Line	Analysts Yahoo	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	Atmos Energy	ATO	$ 114.95	$ 3.35	2.91%	6.48%	7.50%	6.99%	9.90%
2	Black Hills	BKH	57.51	2.65	4.61%	3.44%	N/M	3.44%	8.05%
3	Chesapeake Utilities	CPN	103.77	2.52	2.43%	6.03%	7.60%	6.82%	9.24%
4	New Jersey Resources	NJR	42.00	1.72	4.10%	5.33%	6.00%	5.66%	9.76%
5	NiSource	NI	26.54	1.09	4.11%	3.13%	7.30%	5.22%	9.32%
6	Northwest Natural Holdings	NWN	36.95	1.96	5.30%	4.17%	2.80%	3.48%	8.79%
7	One Gas	OGS	61.47	2.86	4.65%	3.65%	5.00%	4.32%	8.98%
8	Spire	SR	59.91	3.09	5.16%	7.39%	6.36%	6.88%	12.03%
9	Average				***4.16%***	***4.95%***	***6.08%***	***5.35%***	***9.51%***
10	High								12.03%
11	Low								8.05%

* Average of High and Low prices per Yahoo from February 15 to March 31, 2024
** Value Line Projected Dividends for 2024 and 2025 (averaged) published February 23, 2024 and for Black Hills on January 19, 2024
*** For Columns (f) and (g) per workpapers
N/M Below 2% growth estimate disregarded

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

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)	2023/24 Risk Free Rate (R_f)	K_e or 2024-25 CAPM ROE for Each Co. Cols. (e) + (f)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)
	Proxy Group							
1	Atmos Energy	ATO	61.6%	0.85	7.17%	6.09%	4.10%	10.19%
2	Black Hills	BKH	40.3%	1.00	7.17%	7.17%	4.10%	11.27%
3	Chesapeake Utilities	CPK	54.4%	0.80	7.17%	5.74%	4.10%	9.84%
4	New Jersey Resources	NJR	41.1%	0.95	7.17%	6.81%	4.10%	10.91%
5	NiSource	NI	33.9%	0.90	7.17%	6.45%	4.10%	10.55%
6	Northwest Natural Holdings	NWN	44.4%	0.85	7.17%	6.09%	4.10%	10.19%
7	One Gas	OGS	49.4%	0.85	7.17%	6.09%	4.10%	10.19%
8	Spire	SR	40.1%	0.85	7.17%	6.09%	4.10%	10.19%
9	**Average**		**45.7%**	**0.88**	**7.17%**	**6.32%**	**4.10%**	***10.42%***
10	High							11.27%
11	Low							9.84%

Sources

Column (b) Per SEC Filings: Average for the four quarters ended December 2023

Column (c) From the Value Line Investment Survey published February 23, 2024 and for Black Hills on January 19, 2024.

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 2022 per the Ibbotson Clasic Year Book (See Company Exhibit A-14 (TAW-1), Sched. D5, p. 7 of 12

Column (f) Determined as follows 30 Yr US Treasury for 2025 per March 2024 Blue Chip Report **4.10%** Per AG-CE-199 Att. 3

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 | **Case No. U-21490**
Consumers Energy - Gas Rate Case | **Exhibit AG-48**
Date: April 22, 2024
Utility Equity Risk Premium Approach | **Page 1 of 1**

Line	Description (a)	Rate Developed (b)	Note (c)
1	Number of Companies in proxy group	8	
2	Average Rating	A/BBB	1
3	Projected Average of "A" and "BBB" Bonds New Issue Rate	5.78%	2
4	Historical Spread - Gas Util. Common Stocks vs. "A" Rated Utility Bonds	4.15%	3
5	Sub Total - Rate for "A" and "BBB" rated companies (lines 3 + 4)	**9.93%**	

1 Atmos, and OneGas are "A" rated. Black Hills, NiSource and Spire are "BBB" rated and the subsidiaries of Northwest Natural Holdings and New Jersey Resources are "A" rated

2 Based on analysis of 2023 new 30 Year issues (see workpapers)

"BBB" Rated Spread to 30 Yr, Treasuries	1.78%
"A" Rated Spread to 30 Yr. Treasuries	1.57%
Average Spread	1.68%
Assumed 30 Year US Treasury Bond Rate (from CAPM Analysis)	4.10%
Projected Average of "A" / "BBB" 30 Year bonds	**5.78%**

3 Per Company Exhibit A-14 (TAW-1) page 8, line 72

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21490
Exhibit AG-49
Date: April 22, 2024

Peer Group Non-Utility or Non Regulated Operations

Line	Company & Ticker		Percent Common Equity*	Current Beta (*B*)	Utility Business	Non Utility & Non Reg. Business		Measure-ment Criteria	SEC Filing Information SEC Form	Period Ending	Page
	(a)		(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)
	Proxy Group										
1	Atmos Energy	ATO	61.6%	0.85	***66.0%***	***34.0%***	A	Net Income	10-K	Sep. 23	25
2	Black Hills	BKH	40.3%	1.00	***100.0%***	***0.0%***	B	Op. Income	10-K	Dec. 23	40
3	Chesapeake	CPK	54.4%	0.80	***74.0%***	***26.0%***	C	Op. Income	10-K	Dec. 23	31
4	New Jersey Resources	NJR	41.1%	0.95	***50.0%***	***50.0%***	D	Net Income	10-K	Sep. 23	34
5	NiSource	NI	33.9%	0.90	***97.0%***	***3.0%***		Revenues	10-K	Dec. 23	60
6	Northwest Natural Gas	NWN	44.4%	0.85	***97.0%***	***3.0%***		Revenues	10-K	Dec. 23	79 & 85
7	One Gas	OGS	49.4%	0.85	***100.0%***	***0.0%***		Revenues	10-K	Dec. 23	7
8	Spire	SR	40.1%	0.85	***87.0%***	***13.0%***	E	Net Income	10-K	Sep. 23	30
9	**Average**		45.7%	**0.88**	***83.9%***	***16.1%***					

* Reflects Average Capitalization for the four quarters ended December 2023
A Pipeline and Storage
B Utility equals 48% Gas and 52% Electric
C Non Utility is primarily Propane Distribution
D Energy Services, Clean Energy Ventures, Storage and Transportation
E Gas Marketing and Storage and Pipelines

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21490
Exhibit AG-50
Date: April 22, 2024

Market to Book Equity Ratios

Line	Company & Ticker		Dec. 31, 2023 Mkt. Price p/ Sh.	December 31, 2023 Book Value of Common Equity ($Mil.)	Shares Outstanding (Millions)	Book Value Per Sh.	Market to Book Ratio
	(a)		(b)	(c)	(d)	(e)	(f)
	Proxy Group						
1	Atmos Energy	ATO	115.90	11,273.0	150.8	74.75	1.6
2	Black Hills	BKH	53.95	3,215.3	68.3	47.08	1.1
3	Chesapeake Utilities	CPK	105.63	1,246.1	22.2	56.13	1.9
4	New Jersey Resources	NJR	44.58	2,066.2	93.2	22.17	2.0
5	NiSource	NI	28.55	7,783.5	447.4	17.40	1.6
6	Northwest Natural Gas	NWN	38.94	1,283.8	37.6	34.14	1.1
7	One Gas	OGS	63.72	2,765.9	56.5	48.95	1.3
8	Spire	SR	62.34	2,808.8	55.0	51.07	1.2
9	**Average**						**1.5**

Col. (b) Closing Price 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)

Gas Regulatory Decisions - Authorized ROE's under 9.9% - 2022 and 2023

Line	Gas Company*	Order Date & Jurisdiction*			ROE Rate from Order* 2022	2023	Parent Company	Foreign,Prvt, Domestic	Long Term Debt Issued Since Rate Order**			
	(a)		(b)		(c)	(d)	(e)	(f)			(g)	
1	Delta Natural Gas	Jan	3	KY	9.25%		Essential Utilities	D	$500M	5.30%	30 Yr	(May 2022)
2	Piedmont Natural Gas	Jan	6	NC	9.60%		Duke Energy	D	$2.9 Bil	4.0 to 5.3%	10 &30 Yr.	(Aug 2022)
3	Niagra Mohawk Power	Jan	20	NY	9.00%		National Grid PLC	F	$500M	5.76%	30 Yr	(Sep 2022)
4	Public Service of N. Carolina	Jan	21	NC'	9.60%		Dominion Energy	D	$1.0 Bil	4.4 to 4.9%	10 &30 Yr.	(Aug 2022)
5	Southwest Gas	Mar	22	NV	9.40%		Southwest Gas Holdings	D	$600M	4.10%	10 Yr. Debt	(Mar 2022)
6	Southwest Gas	Mar	22	NV	9.40%		Southwest Gas Holdings	D	$600M	4.10%	10 Yr. Debt	(Mar 2022)
7	Orange & Rockland Util.	Apr	14	NY	9.20%		Consolidated Edison	D	$500M	5.20%	10 Yr. Debt	(Feb 2023)
8	Atmos Energy	May	19	KY	9.23%		Atmos Energy	D	$800M	5.45%/5.75%	10 & 30 Yr	(Sep 2022)
9	Corning Natural Gas	Jun	16	NY	9.25%		Arga Infrastructure Ptns.	PVT				
10	Northern Utilities	Jul	20	NH	9.30%		Unitil	D	$25M	5.7%/5.96%	10 &30 Yr.	(Jul 2023)
11	Northern Indiana Pub Serv	Jul	27	IN	9.85%		NISource	D	$300M	5.25%	5 Yr	(May 2023)
12	Avista	Aug	2	OR	9.40%		Avista	D	$250M	5.66%	30 Yr	(Mar 2023)
13	Elizabethtown Gas	Aug	17	NJ	9.60%		South Jersey Industries	PVT				
14	CenterPoint Energy Res.	Aug	18	MN	9.39%		CenterPoint Energy Res.	D	$800M	4.45%/4.85%	10 & 30 Yr	(Sep 2022)
15	Cascade Natural Gas	Aug	23	WA	9.40%		MDU Resources	D	$100M	5.39%	10 Yr	(Nov 2023)
16	Piedmont Natural Gas	Sep	15	SC	9.30%		Duke Energy	D	$350M	5.40%	10 Yr	(Jun 2023)
17	Black Hills Energy Arkansas	Oct	10	AR	9.60%		Black Hills	D	$450M	4.35%	11 Yr	(May 2023)
18	Delmarva Power & Light	Oct	12	DE	9.60%		Exelon	D	$1.7 Bil	5.2/5.4/5.6%	5/10/20 Yrs	(Feb 2024)
19	Northwest Natural Gas	Oct	24	OR	9.40%		Northwest Natural Hldng.	D	$130M	5.18%/5.23%	11 & 15 Yr	(Aug 2023)
20	Public Service of Colorado	Oct	25	CO	9.20%		Xcel Energy	D	$800M	5.45%	10 Yr	(Jul 2023)
21	Berkshire Gas	Oct	27	MA	9.70%		Avangrid	D	$680M	Var. Rates	Var. Mat.	(Dec 2023)
22	Northern States Power	Oct	27	ND	9.80%		Xcel Energy	D	$800M	5.45%	10 Yr	(Jul 2023)
23	Columbia Gas of Maryland	Nov	17	MD	9.65%		NISource	D	$300M	5.25%	5 Yr	(May 2023)
24	New Mexico Gas	Nov	30	NM	9.38%		Emera	F				
25	So. California Gas	Dec	15	CA	9.80%		Sempra	D	$600M	6.88%	30 Yr	(Mar 2024)
26	So. Jersey Gas	Dec	21	NJ	9.60%		South Jersey Industries	PVT				
27	Pudget Sound Energy	Dec	22	WA	9.40%		Alberta IM & Brit. Col IM	PVT				
28	Wisconsin Public Service	Dec	22	WI	9.80%		WEC Energy	D	$1.1 Bil	4.75%	3 & 5 Yr.	(Jan 2023)
29	Dominion Energy	Dec	23	UT	9.60%		Dominion Energy	D	$1.0 Bil	5/5.35%	10/30 Yr.	(Feb 2024)
30	Wisconsin Eletric Power	Dec	29	WI	9.80%		Xcel Energy	D	$800M	5.45%	10 Yr	(Jul 2023)
31	Wisconsin Gas	Dec	29	WI	9.65%		Xcel Energy	D	$800M	5.45%	10 Yr	(Jul 2023)
32	**Average for 2022**				9.49%							

* Per Regulatory Research Associates with Summary of All Orders on Page 4
** Per various SEC Filings

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-21490**

Consumers Energy - Gas Rate Case **Exhibit AG-51**

Date: April 22, 2024

Gas Regulatory Decisions - Authorized ROE's under 9.9% - 2022 and 2023

Line	Gas Company*	Order Date & Jurisdiction*			ROE Rate from Order* 2022	2023	Parent Company	Foreign,Prvt, Domestic	Long Term Debt Issued Since Rate Order**			
	(a)		(b)		(c)	(d)	(e)	(f)		(g)		
1	Texas Gas Service	Jan	19	TX		9.60%	One Gas	D	$300M	5.10%	6 Yr	(Dec 2023)
2	Southwest Gas	Jan	23	AZ		9.30%	Southwest Gas Holdings	D	$300M	5.45%	5 Yr	(Mar 2023)
3	Columbia Gas of Ohio	Jan	26	OH		9.60%	NiSource	D	$300M	5.25%	5 Yr	(May 2023)
4	Northern States Power	Mar	23	MN		9.57%	Xcel Energy	D	$800M	5.45%	10 Yr	(Jul 2023)
5	Pivotal Utility Holdings	Mar	28	FL		9.50%	Chesapeake Utilities	D	$550M	Var. Rates	Var. Mat.	(Nov 2023)
6	Atmos Energy	May	4	CO		9.30%	Atmos	D	$900M	5.9%/6.5%	10 & 30 Yr	(Oct 2022)
7	Intermountain Gas	Jun	30	ID		9.50%	MDU Resources	D	$100M	5.39%	10 Yr	(Nov 2023)
8	Consolidated Edison of NY	Jul	20	NY		9.25%	Consolidated Edison	D				
9	Michigan Gas Utilities	Aug	30	MI		9.80%	WEC Energy	D				
10	Avista	Aug	31	ID		9.40%	Avista	D				
11	Northern Utilities	Sep	20	ME		9.35%	Unitil	D				
12	Dominion Energy SC	Sep	20	SC		9.49%	Dominion	D	$1.0 Bil	5/5.35%	10/30 Yr.	(Feb 2024)
13	Piedmont Natural Gas	Oct	5	SC		9.30%	Duke Energy	D	$150M	4.85%	3/5 Yr	(Nov 2023)
14	Chattanooga Gas	Oct	6	TN		9.80%	Southern Co.	D	$400M	5.70%	10 Yr	(Feb 2024)
15	New Youk State Elec. & Gas	Oct	12	NY		9.20%	Avangrid	D	$680M	Var. Rates	Var. Mat.	(Dec 2023)
16	Rochester Gas & Electric	Oct	12	NY		9.20%	Avangrid	D	$680M	Var. Rates	Var. Mat.	(Dec 2023)
17	Northwestern Energy	Oct	25	MT		9.55%	NorthWestern Energy	D				
18	Minnesota Energy Rescs	Oct	26	MN		9.65%	WEC Energy	D				
19	Avista	Oct	26	OR		9.50%	Avista	D				
20	Duke Energy Onio	Nov	1	OH		9.60%	Duke Energy	D	$150M	4.85%	3/5 Yr	(Nov 2023)
21	Madison Gas & Electric	Nov	3	WI		9.70%	MGE Corp	D				
22	Questar Gas	Nov	7	WY		9.65%	Dominion Energy	D	$1.0 Bil	5/5.35%	10/30 Yr.	(Feb 2024)
23	Northern States Power	Nov	9	FL		9.80%	Xcel Energy	D				
24	Wisconsin Power & Light	Nov	9	WI		9.80%	Alliant Energy	D				
25	Ameren Illinois	Nov	16	IL		9.44%	Ameren	D	$700M	4.38%	5 Yr	(Dec 2023)
26	North Shore Gas	Nov	16	IL		9.38%	WEC Energy	D	$20M	5.82%	5 Yr	(Dec 2023)
27	Northern Illinois Gas	Nov	16	IL		9.51%	Southern Co.	D	$400M	5.70%	10 Yr	(Feb 2024)
28	Peoples Gas Light & Coke	Nov	16	IL		9.38%	WEC Energy	D				
29	Piedmont Natural Gas	Dec	4	TN		9.80%	Duke Energy	D	$150M	4.85%	3/5 Yr	(Nov 2023)
30	Baltimore Gas & Electric	Dec	14	MD		9.45%	Exelon	D	$1.7 B	5.2/5.4/5.6%	5/10/20 Yrs	(Feb 2024)
31	Washington Gas Light	Dec	14	MD		9.50%	AltaGas	F				
32	Washington Gas Light	Dec	15	MD		9.65%	AltaGas	F				
33	Mountaineer Gas	Dec	21	WV		9.75%	UGI	D				
34	**Average for 2023**					**9.52%**						

* Per Regulatory Research Associates with Summary of All Orders on Page 4

** Per various SEC Filings

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-21490**
Consumers Energy - Gas Rate Case **Exhibit AG-51**
Date: April 22, 2024
Gas Regulatory Decisions - Authorized ROE's Summary for all Cases - 2022 and 2023

		Total Year 2022		Total Year 2023	
Line	Caption	# of Orders	Avg. ROE	# of Orde	Avg. ROE
	(a)	(b)	(c)	(d)	(e)
1	**Average Authorized ROE's page 1 and 2**	31	9.49%	33	9.52%
	ROE Orders At 9.9% or Higher				
2	Michigan Cases				
3	Consumers Energy Gas	1	9.90%	1	9.90%
4	California Case				
5	San Diego Gas & Electric	1	10.20%		
6	Florida Cases				
7	Florida Public Utilities*			1	10.25%
8	Peoples Gas System**			1	10.15%
9	Total Number At 9.90% or Higher	2		3	
10	Tota/Avg. of All Cases	**33**	**9.52%**	**36**	**9.57%**

* Small Florida company operating in four counties with 83,000 customers

** Small Florida company operating in central Florida (near Lakeland), the west coast of Florida (Sarasota) and on the east coast of Florida (Jupiter) with approximately 400,000 customers.

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21490**
Consumers Energy Company - Gas Rate Case | **Exhibit AG-52**
Date: April 22, 2024
Page 1 of 1

Rating Agency Cash Flow Ratios
(With ROE at 9.85% and a 50% Common Equity Ratio)

		2022 Adjusted Moody's Cash Flow Ratio ($ Millions)			
		Cash From			
		Operations		Ratio	
Line	Caption	Pre-Wkg. Cap.	Debt	(e) / (f)	Note
	(a)	(b)	(c)	(d)	
1	**2022 Actual Ratio Results**	$ 2,114	$ 10,472	**20.2%**	1
2	Adjust Comon Equity	N/A	N/A		2
3	Increase ROE (to 9.8% vs 9.5%)	31			3
4	**Pro Forma w/50% Common Equity, 9.5% ROE**	$ 2,145	$ 10,472	**20.5%**	L 1 + L 2 + L 3
5	**Ratings Downgrade Risk**			***Below 18%***	4

Notes

1 From page 1 of Moody's May 31, 2023 report on Consumers Energy (see AG-CE-128)

2 No adjjustment made since the Company's capital structure at year end 2022 is essentially balanced.
Common Equity of CECo at year-end December 2022 was $10.1 billion and long-term debt plus current maturities were $10.2 billion (per CMS 2022 10-K, p. 103)
Moody's uses $10.5 billion of debt in their analysis which include the $10.2 billion noted above plus an additional $0.3 billion for short term debt, leases
and other adjustments.

3 CECo Net Income in 2022 was $943 million. Average Common Equity per Exhibit A-4 (HLR-23) was $9,881 million. Therefore ROE earned was 9.54%
Had CECo earned 9.85%, its net income and earnings for this test would be higher by 0.31% x $9.9 Billion or by $31 million.

4 From page 2 of Moody's May 24, 2022 report on Consumers Energy (see AG-CE-257)

U21490-AG-CE-0128
Page **1** of **1**

Question:

3. Provide a copy of all rating agency reports covering Consumers Energy and CMS Energy for the most recent 24 months.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that information regarding CMS Energy is irrelevant to this matter as 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 attached.

Witness: MARC R. BLECKMAN
Date: March 1, 2024

THE REST OF THIS EXHIBIT CONSISTS OF 70 PAGES OF RATING AGENCY REPORTS

THE MOODY'S REPORT DATED MAY 31, 2023 IS ON PAGES 34 TO 41 OF THE PDF

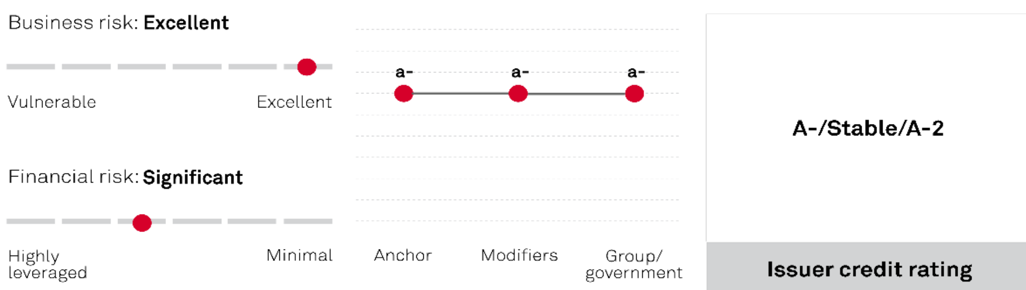
S&P Global
Ratings

RatingsDirect®

Consumers Energy Co.

August 17, 2023

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Monopolistic vertically integrated electric utility and gas distribution utility operations.	Lack of operating diversity makes the company largely depend on Michigan regulators to sustain its credit quality.
Favorable regulatory construct in Michigan.	Exposure to environmental risks due to its dependence on natural gas and coal-fired generation (about 70% of electricity generated or purchased in 2022), though this is partially mitigated by a plan to retire coal by 2025.
Large customer base of 1.9 million electric and 1.8 million gas customers.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.
The company is an insulated subsidiary of its parent, CMS Energy, allowing us to rate it one notch above the parent.	Susceptibility to adverse weather events, including winter storms.
	Exposure to cyclical commercial and industrial customers, which account for about 47% of electric revenues and 20% of gas revenues.

We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk. We view Michigan's regulatory construct as above average compared to peers because of the benefit of a streamlined 10-month rate case process and various constructive rate mechanisms, such as the use of forward test-years, power supply and natural gas cost rider adjustments, and partial decoupling for the gas business. These mechanisms help the company earn its allowed ROE and minimize regulatory lag.

CE is currently in the middle of both an electric rate case and a gas rate case. The company filed for a $207.1 million electric rate increase based on a 10.25% return on equity (ROE) in May and reached a settlement with various intervenors for a $95 million gas rate increase based on a 9.90% ROE in July. We expect final rate orders by the end of 2023 and continue to monitor related developments.

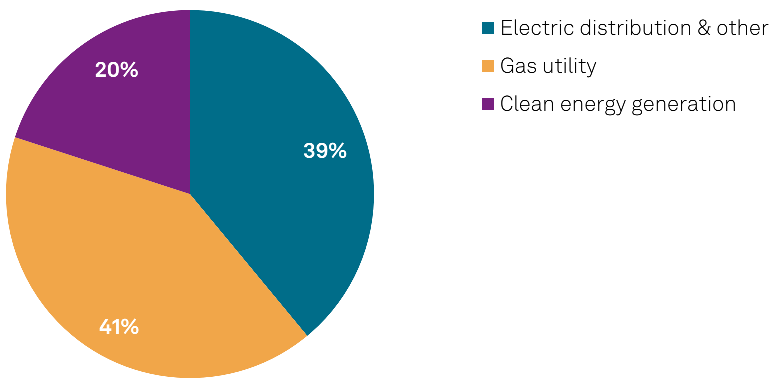
Consumers Energy Co. rate case details

	Present electric rate case: requested by company 5/1/2023	Previous electric rate case: authorized by Commission 1/19/2023	Present gas rate case: settlement filed 7/21/2023	Previous gas rate case: authorized by Commission 7/7/2022
Rate change amount ($ mil.)	207.1	155.0	95.0	170.0
Rate base ($ mil)	14,354.2	N/A	N/A	N/A
Rate base valuation method	Average	Average	Average	Average
Return on equity (%)	10.25	9.90	9.90	9.90
Common equity to total capital (%)	42.58	N/A	N/A	N/A
Rate of return (%)	6.11	N/A	N/A	N/A
Rate case test year end date	2/28/2025	12/31/2023	N/A	9/30/2023

Source: S&P CapitalIQ Pro. N/A—Not applicable.

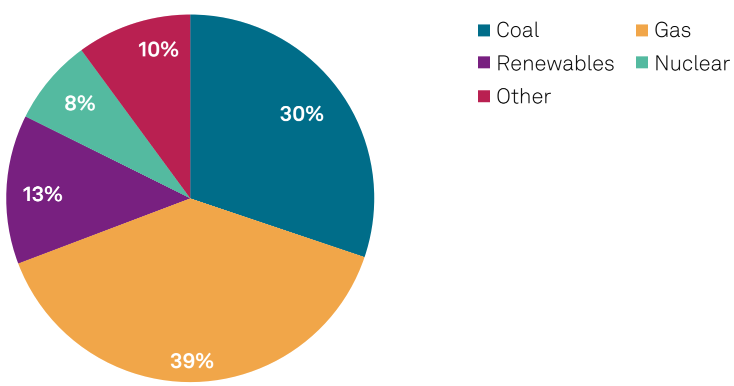
The company's elevated capital spending plan prioritizes infrastructure upgrades, and its energy transition plans. Over the next five years, CE plans to spend about $15.5 billion to maintain and upgrade its gas infrastructure and electric distribution systems and reduce its carbon emission. The capital plan includes investment of about $6.3 billion in the gas segment and about $9.2 billion in the electric segment. The company also intends to reduce its carbon exposure in line with its Integrated Resource Plan (IRP), which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 for CE’s electric division and a goal to retire CE’s owned coal-fired generation plants by 2025. Furthermore, the company's IRP targets a gradual reduction in its gas-fired generation dependance after 2025 as well as a target to meet 90% of its customer needs with clean energy sources by 2040. In addition, the company also announced a net-zero greenhouse gas emissions target for its gas distribution system by 2050.

Consumers Energy Co.'s investment plan



Source: Company fillings.

Consumers Energy Co.'s electricity generated and purchased by source



Source: Company filings.

The MPSC is currently investigating CE for malfunctioning meters and estimated billings. The company informed investors during its earnings call that meter vendors faced supply-chain issues since the start of the pandemic, which delayed the deployment of the company's updated meters moving to 5G from 3G. Given these delays, there were some issues with meter reads as more wireless carriers moved to 5G. This said, the company expects more consistent meter reads by the end of August. We continue to monitor the developments surrounding this investigation.

We expect CE's credit measures to remain within the significant financial risk profile category. Throughout our base-case scenario, we expect CE's funds from operations (FFO) to debt to be between 18%-20%.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of about 18%-20%.

Downside scenario

We could lower our rating on Consumers Energy if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or
- We could also lower our rating on Consumers Energy if we lower our rating on parent CMS Energy Corp.

Upside scenario

Although less likely, we could raise our rating on Consumer's Energy if we raise our rating on CMS Energy and Consumers Energy's stand-alone financial measures improve, reflecting FFO to debt 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 about $3 billion annually;
- Annual dividends averaging about $960 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

Consumers Energy Inc.—Forecast summary

Period ending	2021a	2022a	2023e	2024f	2025f	2026f	2027f
(Mil. $)							
Revenue	6,987	8,117	7,932	8,376	8,896	9,428	9,985
EBITDA (reported)	2,252	2,321	2,653	2,902	3,143	3,392	3,655
Plus: Operating lease adjustment (OLA) rent	8	6	6	6	6	6	6
Plus/(less): Other	146	70	51	(47)	(58)	(58)	(65)
EBITDA	2,406	2,397	2,710	2,861	3,092	3,340	3,595
Less: Cash interest paid	(375)	(342)	(406)	(478)	(533)	(573)	(605)
Less: Cash taxes paid	10	2	--	(102)	(41)	(92)	(66)

Consumers Energy Inc.—Forecast summary

Funds from operations (FFO)	2,041	2,058	2,303	2,281	2,518	2,675	2,925
Cash flow from operations (CFO)	2,014	985	2,717	2,221	2,471	2,585	2,798
Capital expenditure (capex)	2,136	2,275	3,707	2,823	3,117	2,765	2,737
Free operating cash flow (FOCF)	(123)	(1,290)	(990)	(602)	(647)	(180)	61
Dividends	724	771	788	913	968	1,044	1,099
Discretionary cash flow (DCF)	(847)	(2,061)	(1,778)	(1,515)	(1,615)	(1,224)	(1,038)
Debt (reported)	8,810	10,287	11,585	12,402	13,217	13,838	14,354
Plus: Lease liabilities debt	74	81	89	99	110	124	140
Plus: Pension and other postretirement debt	--	--	--	--	--	--	--
Less: Accessible cash and liquid Investments	(22)	(43)	(43)	(43)	(43)	(43)	(43)
Plus/(less): Other	535	680	27	98	180	267	355
Debt	9,397	11,005	11,658	12,556	13,465	14,186	14,807
Equity	9,279	10,155	10,885	11,687	12,603	13,369	14,096
Cash and short-term investments (reported)	22	43	43	43	43	43	43
Adjusted ratios							
Debt/EBITDA (x)	3.9	4.6	4.3	4.4	4.4	4.2	4.1
FFO/debt (%)	21.7	18.7	19.8	18.2	18.7	18.9	19.8
FFO cash interest coverage (x)	6.4	7.0	6.7	5.8	5.7	5.7	5.8
EBITDA interest coverage (x)	6.3	6.4	6.2	5.7	5.5	5.6	5.7
CFO/debt (%)	21.4	8.9	23.3	17.7	18.3	18.2	18.9
FOCF/debt (%)	(1.3)	(11.7)	(8.5)	(4.8)	(4.8)	(1.3)	0.4
DCF/debt (%)	(9.0)	(18.7)	(15.3)	(12.1)	(12.0)	(8.6)	(7.0)
Debt/debt and equity (%)	50.3	52.0	51.7	51.8	51.7	51.5	51.2

All figures adjusted by S&P Global Ratings. a—Actual. e—Estimate. f—Forecast.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE'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. CE contributes to about 95% of CMS' EBITDA.

Peer Comparison

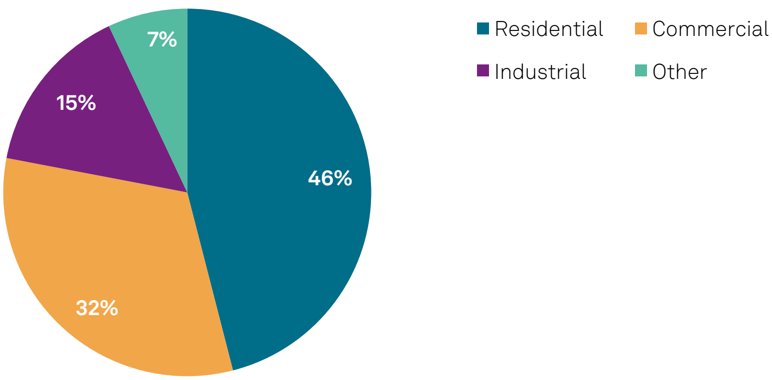
Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Wisconsin Power & Light Co.	Wisconsin Electric Power Co.	Consolidated Edison Co. of New York Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31	2022-12-31	2022-12-31
Mil.	$	$	$	$	$
Revenue	8,117	6,353	1,856	4,070	13,268
EBITDA	2,397	2,715	742	1,614	4,048
Funds from operations (FFO)	2,058	2,389	562	986	3,140
Interest	374	551	123	230	890
Cash interest paid	342	359	124	540	821
Operating cash flow (OCF)	985	1,654	286	726	3,264
Capital expenditure	2,275	2,617	1,007	1,018	3,563
Free operating cash flow (FOCF)	(1,290)	(964)	(721)	(293)	(299)
Discretionary cash flow (DCF)	(2,061)	(1,727)	(926)	(922)	(1,277)
Cash and short-term investments	43	15	5	6	1,056
Gross available cash	43	15	5	6	1,056
Debt	11,005	11,528	3,406	5,843	21,344
Equity	10,155	9,695	3,491	4,152	16,878
EBITDA margin (%)	29.5	42.7	40.0	39.7	30.5
Return on capital (%)	6.3	7.6	8.1	11.8	5.8
EBITDA interest coverage (x)	6.4	4.9	6.0	7.0	4.5
FFO cash interest coverage (x)	7.0	7.6	5.5	2.8	4.8
Debt/EBITDA (x)	4.6	4.2	4.6	3.6	5.3
FFO/debt (%)	18.7	20.7	16.5	16.9	14.7
OCF/debt (%)	8.9	14.3	8.4	12.4	15.3
FOCF/debt (%)	(11.7)	(8.4)	(21.2)	(5.0)	(1.4)
DCF/debt (%)	(18.7)	(15.0)	(27.2)	(15.8)	(6.0)

Business Risk

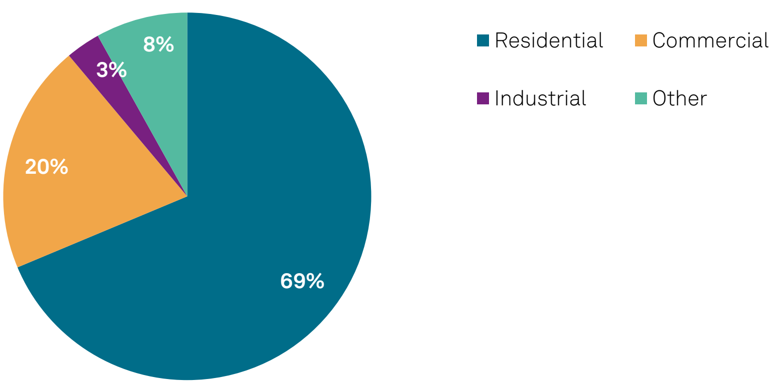
Our assessment of CE's business risk profile reflects the company's monopolistic electric and natural gas utility operations and effective management of regulatory risk. The Michigan Public Service Commission (MPSC) regulates CE and we view the regulatory environment in Michigan as above average compared to peers. This is demonstrated through the company's use of forward-looking test years and a streamlined 10-month rate case process. Furthermore, CE benefits from 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 nonfuel revenues with the revenues approved by the MPSC. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag. The company also actively manages its gas supply for its gas system as it injects natural gas into storage during the summer months for use during the winter months. During 2022, 48 percent of the natural gas supplied to all customers during the winter months was supplied from storage. Furthermore, CE's business risk profile is bolstered by the company's large customer base of about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan. This said, the company is exposed to cyclical commercial and industrial customers for its electric operations which contribute about 47% of the company's electric revenues.

Consumers Energy Co.'s electrical revenue by customer class



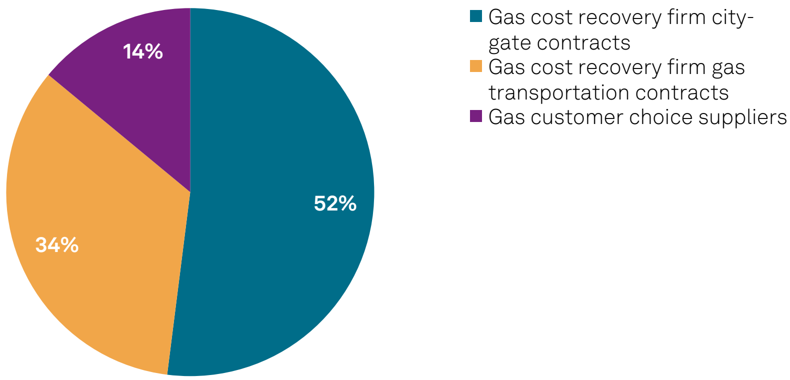
Source: Company filings.

Consumers Energy Co.'s gas revenue by customer class



Source: Company filings.

Consumers Energy Co.'s gas supply sources



Source: Company filings.

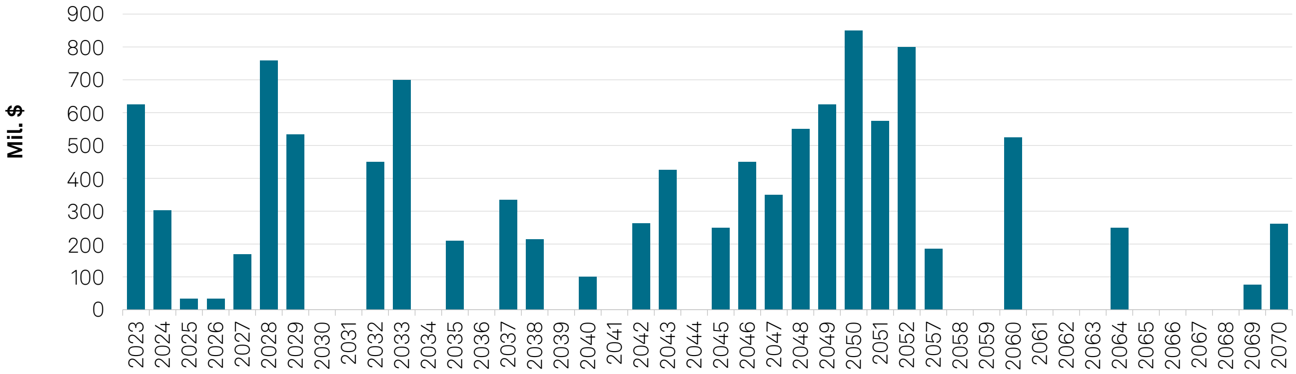
Financial Risk

We assess CE'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 around $3 billion annually over the forecast period (inclusive of the company's acquisition of the Covert gas plant), dividends averaging about $960 million annually, equity injections by the parent to maintain the company's capital structure, securitization issuance related to the retirement costs of the company's Karn coal plant units 1 and 2, continued use of existing regulatory mechanisms, negative discretionary cash flow, and refinancing of all debt maturities. As such, we anticipate financial measures to be consistent with the middle of the range for the significant financial risk category. Specifically, we forecast FFO to debt between 18%-20%.

Debt maturities

Debt Maturities

As of June 2023



Source. Company filings

Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022
Reporting period	2017a	2018a	2019a	2020a	2021a	2022a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,187	6,430	6,341	6,155	6,987	8,117
EBITDA	2,267	2,152	2,252	2,392	2,406	2,397
Funds from operations (FFO)	1,954	1,665	1,823	1,968	2,041	2,058
Interest expense	347	355	335	393	380	374
Cash interest paid	314	331	296	373	375	342
Operating cash flow (OCF)	1,792	1,533	1,688	1,265	2,014	985
Capital expenditure	1,721	1,920	2,191	2,254	2,136	2,275
Free operating cash flow (FOCF)	71	(387)	(502)	(989)	(123)	(1,290)
Discretionary cash flow (DCF)	(453)	(918)	(1,094)	(1,628)	(847)	(2,061)
Cash and short-term investments	44	39	11	20	22	43
Gross available cash	44	39	11	20	22	43
Debt	7,037	7,774	8,238	9,113	9,397	11,005
Common equity	6,488	6,920	7,737	8,556	9,279	10,155
Adjusted ratios						
EBITDA margin (%)	36.6	33.5	35.5	38.9	34.4	29.5
Return on capital (%)	9.8	7.9	7.7	7.5	6.9	6.3
EBITDA interest coverage (x)	6.5	6.1	6.7	6.1	6.3	6.4
FFO cash interest coverage (x)	7.2	6.0	7.2	6.3	6.4	7.0
Debt/EBITDA (x)	3.1	3.6	3.7	3.8	3.9	4.6
FFO/debt (%)	27.8	21.4	22.1	21.6	21.7	18.7
OCF/debt (%)	25.5	19.7	20.5	13.9	21.4	8.9

Consumers Energy Co.--Financial Summary

FOCF/debt (%)	1.0	(5.0)	(6.1)	(10.9)	(1.3)	(11.7)
DCF/debt (%)	(6.4)	(11.8)	(13.3)	(17.9)	(9.0)	(18.7)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2022									
Company reported amounts	10,287	10,155	8,151	2,321	1,233	335	2,397	994	771	2,239
Cash taxes paid	-	-	-	-	-	-	2	-	-	-
Cash interest paid	-	-	-	-	-	-	(331)	-	-	-
Lease liabilities	81	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	6	1	1	(1)	5	-	-
Accessible cash and liquid investments	(43)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	2	(2)	(2)	-	(2)
Share-based compensation expense	-	-	-	25	-	-	-	-	-	-
Securitized stranded costs	(170)	-	(34)	(34)	(6)	(6)	6	(28)	-	-
Power purchase agreements	356	-	-	51	14	14	(14)	38	-	38
Asset-retirement obligations	589	-	-	28	28	28	-	-	-	-
Nonoperating income (expense)	-	-	-	-	(8)	-	-	-	-	-
Reclassification of interest and dividend cash flows	-	-	-	-	-	-	-	(22)	-	-
Debt: other	(95)	-	-	-	-	-	-	-	-	-
Total adjustments	718	-	(34)	76	29	39	(340)	(9)	-	36
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	11,005	10,155	8,117	2,397	1,262	374	2,058	985	771	2,275

Liquidity

We assess CE's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecasted consolidated EBITDA declines by 10%. We believe the supportive regulatory framework provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, CE has the ability to absorb high-impact, low-probability events, in our view, as the company maintains about $1.1 billion in committed credit facilities through 2027, maintains another $250 million in committed credit facilities through

November 2024, and can likely lower its capital spending (averaging about $3 billion annually) during stressful periods, indicative of a limited need for refinancing under such conditions. CE can borrow $500 million from the parent CMS Energy as per its renewed credit agreement in December 2022. Furthermore, our assessment reflects the company's prudent risk management and sound relationships with its banking group. Overall, we believe that the company should be able to withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has around $300 million of long-term debt maturities coming up in 2024 and we expect the company to proactively address these maturities well in advance of their scheduled due dates.

Principal liquidity sources

- Cash FFO of about $2.3 billion;
- Credit facilities of about $1.3 billion;
- Working capital inflows of about $150 million; and
- Available cash of about $100 million.

Principal liquidity uses

- Debt maturities of about $700 million over the next 12 months;
- Estimated maintenance capital spending of about $1.9 billion; and
- Dividends of about $850 million.

Environmental, Social, And Governance

Environmental factors are a moderately negative consideration in our credit rating analysis of CE. The company's use of above-average fossil fuel generation sources exposes it to heightened climate transition risk. The utility's generation capacity portfolio consists of 24% natural gas, 33% coal, 22% renewables, and 21% oil/gas as of Dec. 31, 2022. Slightly mitigating this risk is the utility's accelerated coal retirement plan, which includes a goal to be coal-free by 2025 and have 90% of its capacity portfolio sourced from clean energy resources by 2040.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy because we view the utility as integral to the group's identity, highly unlikely to be sold 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 CE 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 are:

- CE 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.
- CE 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.
- CE 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 CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE 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 CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

CE's capital structure consists of about $10.9 billion of long-term debt, including about $10.8 billion in first-mortgage bonds (FMBs) and about $110 million of tax-exempt revenue bonds.

Analytical conclusions

We rate the company's senior unsecured debt 'A-', in-line with the long-term issuer credit rating on CE as the rated issuances are senior unsecured debt issued by a qualifying investment grade utility as per our criteria.

We base our 'A-2' short-term rating on CE on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- 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 that qualify for a recovery rating as defined in our criteria.
- CE'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.

Rating Component Scores

Foreign currency issuer credit rating	A-/Stable/A-2
Local currency 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-
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)

Rating Component Scores

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 on SACP)

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- 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
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, 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: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of August 17, 2023)*

Consumers Energy Co.

Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2

Ratings Detail (as of August 17, 2023)*

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-
Preferred Stock	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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Tear Sheet:

CMS Energy Corp.'s Recent Stranded Cost Securitization Is Consistent With Our Expectations

December 15, 2023

On Dec. 12, 2023, CMS Energy Corp. announced that Consumers 2023 Securitization Funding LLC issued $646 million of securitization bonds. The securitization issuance was consistent with our base case and finalizes CMS' previously announced plans to securitize and recover the costs related to the retirement of its Karn coal plant units 1 & 2. We view this securitization as supportive of credit quality, allowing the utility to fully recover its costs associated with these coal plants. For our financial analysis of CMS, we deconsolidate securitization debt (and associated revenues and expenses), primarily reflecting the irrevocable non-bypassable charge on CMS' customer bills and the first-priority security interest in the transition property.

Under our base case, we continue to assume CMS' funds from operations (FFO) to debt will remain consistently between 13% and 15%. Under our base-case scenario, we expect elevated capital spending averaging $3.0 billion-$3.5 billion annually over the forecast period and dividends averaging $700 million-$750 million annually. We also forecast limited growth of NorthStar as a proportion of the overall company, continued use of existing regulatory mechanisms, continued negative discretionary cash flow that we expect it will fund will in a balanced manner, and the refinancing of all debt maturities.

We assess CMS' 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. As such, we expect the company's financial measures will consistently reflect the lower end of the range for its significant financial risk profile category.

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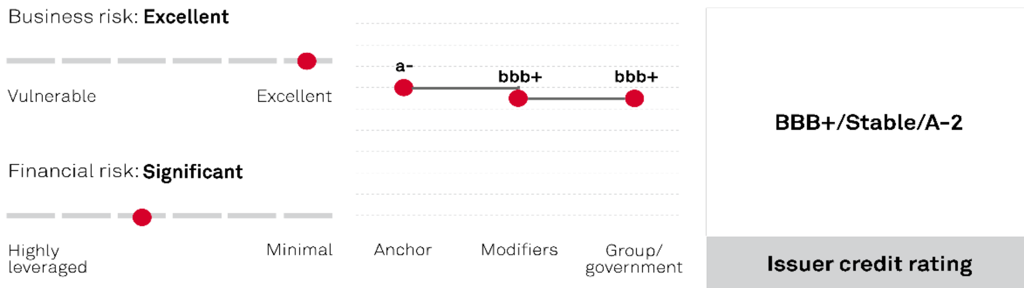
Ratings Score Snapshot



Company Description

CMS is a vertically integrated regulated utility holding company that derives about 95% of its EBITDA from its regulated utility operations at subsidiary Consumers Energy Co. (CE). The remainder comes from its nonregulated electric generation business NorthStar Clean Energy (previously CMS Enterprises). CE operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE'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. NorthStar is an independent power producer and marketer that contracts much of its generation assets in its portfolio to high-credit-quality counterparties and sells electricity on a merchant basis.

Outlook

The stable outlook on CMS reflects our expectation that it will continue focusing on its core utility operations and reach constructive regulatory outcomes to avoid increasing its business risk. The outlook also reflects our base-case forecast for consolidated FFO to debt of 13%-15% over the forecast period, which is on the lower end of the range for the significant financial risk profile category.

Downside scenario

We could lower our rating on CMS over the next 24 months if:

- Its business risk profile weakens because of reduced regulatory support or a material increase in its nonutility operations; and
- Its financial measures consistently underperform our base-case forecast and decline such that its FFO to debt remains consistently below 13%.

This could occur if the company's rate case outcomes are consistently weaker than expected, it faces greater regulatory lag, or it increases its primarily debt-financed capital spending.

Upside scenario

We could raise the rating on CMS over the next 24 months if:

- Its business risk profile remains robust; and
- Its financial measures strengthen such that they consistently exceed our base-case assumptions, including FFO to total debt of more than 16%.

We believe the company could improve its financial measures through deleveraging, greater equity funding of its capital investments, and continuous cash flow support from its rate case activity.

Key Metrics

CMS Energy Corp.--Forecast summary

Period ending	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. $)	2021a	2022a	2023e	2024f	2025fe	2026f	2027f
Revenue	7,295	8,562	8,069	8,705	9,207	9,804	10,387
EBITDA (reported)	2,260	2,350	2,525	2,896	3,129	3,410	3,678
Plus: Operating lease adjustment (OLA) rent	8	6	6	6	6	6	6
Plus/(less): Other	144	72	86	(17)	(50)	(51)	(54)
EBITDA	2,412	2,428	2,617	2,885	3,086	3,365	3,630
Less: Cash interest paid	(546)	(509)	(531)	(589)	(678)	(747)	(811)
Less: Cash taxes paid	(16)	(1)	(47)	(62)	--	(45)	(32)
Funds from operations (FFO)	1,850	1,917	2,039	2,234	2,407	2,573	2,787
Cash flow from operations (CFO)	1,871	859	2,596	2,177	2,386	2,448	2,673
Capital expenditure (capex)	2,160	2,410	3,876	3,077	3,620	3,226	3,138
Free operating cash flow (FOCF)	(290)	(1,550)	(1,279)	(899)	(1,233)	(778)	(464)
Dividends	551	598	652	720	773	823	878
Discretionary cash flow (DCF)	(840)	(2,148)	(1,932)	(1,619)	(2,006)	(1,601)	(1,342)
Debt (reported)	12,422	14,232	15,728	17,010	18,114	18,905	19,469
Plus: Lease liabilities debt	78	108	151	213	303	433	623
Plus: Pension and other postretirement debt	--	--	--	--	--	--	--
Less: Accessible cash and liquid Investments	(452)	(164)	(164)	(164)	(164)	(164)	(164)
Plus/(less): Other	(60)	(250)	(905)	(920)	(867)	(781)	(690)
Debt	11,988	13,926	14,810	16,139	17,385	18,393	19,238
Equity	8,193	8,600	9,046	9,598	10,310	11,036	11,732
Cash and short-term investments (reported)	452	164	164	164	164	164	164
Adjusted ratios							
Debt/EBITDA (x)	5.0	5.7	5.7	5.6	5.6	5.5	5.3
FFO/debt (%)	15.4	13.8	13.8	13.8	13.8	14.0	14.5
FFO cash interest coverage (x)	4.4	4.8	4.8	4.8	4.5	4.4	4.4
EBITDA interest coverage (x)	4.6	4.8	4.7	4.7	4.4	4.4	4.4
CFO/debt (%)	15.6	6.2	17.5	13.5	13.7	13.3	13.9
FOCF/debt (%)	(2.4)	(11.1)	(8.6)	(5.6)	(7.1)	(4.2)	(2.4)
DCF/debt (%)	(7.0)	(15.4)	(13.0)	(10.0)	(11.5)	(8.7)	(7.0)
Debt/debt and equity (%)	59.4	61.8	62.1	62.7	62.8	62.5	62.1

All figures are adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. $--U.S. dollar.

Financial Summary

CMS Energy Corp.--Financial Summary

Period ending	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022
Reporting period	2017a	2018a	2019a	2020a	2021a	2022a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,548	6,839	6,810	6,646	7,295	8,562
EBITDA	2,361	2,263	2,381	2,561	2,412	2,428
Funds from operations (FFO)	1,890	1,891	1,954	1,951	1,850	1,917
Interest expense	509	517	527	594	528	506
Cash interest paid	466	495	485	668	546	509
Operating cash flow (OCF)	1,782	1,795	1,910	1,273	1,871	859
Capital expenditure	1,754	2,172	2,210	2,401	2,160	2,410
Free operating cash flow (FOCF)	28	(377)	(300)	(1,128)	(290)	(1,550)
Discretionary cash flow (DCF)	(347)	(790)	(767)	(1,637)	(840)	(2,148)
Cash and short-term investments	182	153	140	168	452	164
Gross available cash	182	153	140	168	452	164
Debt	11,196	12,214	13,364	14,998	11,988	13,926
Common equity	4,478	5,032	5,610	7,082	8,193	8,600
Adjusted ratios						
EBITDA margin (%)	36.1	33.1	35.0	38.5	33.1	28.4
Return on capital (%)	9.1	8.0	7.1	6.9	5.8	5.9
EBITDA interest coverage (x)	4.6	4.4	4.5	4.3	4.6	4.8
FFO cash interest coverage (x)	5.1	4.8	5.0	3.9	4.4	4.8
Debt/EBITDA (x)	4.7	5.4	5.6	5.9	5.0	5.7
FFO/debt (%)	16.9	15.5	14.6	13.0	15.4	13.8
OCF/debt (%)	15.9	14.7	14.3	8.5	15.6	6.2
FOCF/debt (%)	0.2	(3.1)	(2.2)	(7.5)	(2.4)	(11.1)
DCF/debt (%)	(3.1)	(6.5)	(5.7)	(10.9)	(7.0)	(15.4)

Peer Comparison

CMS Energy Corp.--Peer Comparisons

	CMS Energy Corp.	DTE Energy Co.	Alliant Energy Corp.	Ameren Corp.	WEC Energy Group Inc.
Foreign currency issuer credit rating	BBB+/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	BBB+/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31	2022-12-31	2022-12-31
Mil.	$	$	$	$	$

CMS Energy Corp.--Peer Comparisons

Revenue	8,562	19,184	4,205	7,957	9,597
EBITDA	2,428	3,481	1,620	3,009	3,299
Funds from operations (FFO)	1,917	2,855	1,286	2,495	2,732
Interest	506	850	334	547	562
Cash interest paid	509	629	328	523	515
Operating cash flow (OCF)	859	1,965	469	2,204	2,112
Capital expenditure	2,410	3,367	1,468	3,354	2,345
Free operating cash flow (FOCF)	(1,550)	(1,402)	(999)	(1,151)	(233)
Discretionary cash flow (DCF)	(2,148)	(2,171)	(1,456)	(1,779)	(1,237)
Cash and short-term investments	164	33	20	250	29
Gross available cash	164	33	20	490	29
Debt	13,926	19,924	9,139	14,543	17,737
Equity	8,600	10,856	6,276	10,573	11,851
EBITDA margin (%)	28.4	18.1	38.5	37.8	34.4
Return on capital (%)	5.9	6.7	7.1	6.6	7.7
EBITDA interest coverage (x)	4.8	4.1	4.9	5.5	5.9
FFO cash interest coverage (x)	4.8	5.5	4.9	5.8	6.3
Debt/EBITDA (x)	5.7	5.7	5.6	4.8	5.4
FFO/debt (%)	13.8	14.3	14.1	17.2	15.4
OCF/debt (%)	6.2	9.9	5.1	15.2	11.9
FOCF/debt (%)	(11.1)	(7.0)	(10.9)	(7.9)	(1.3)
DCF/debt (%)	(15.4)	(10.9)	(15.9)	(12.2)	(7.0)

Environmental, Social, And Governance

Environmental factors are a moderately negative consideration in our credit rating analysis of CMS. The company’s use of above-average fossil fuel generation sources exposes it to heightened climate transition risks. The company’s generation capacity portfolio comprises 31% natural gas, 26% coal, 25% renewables, 16% oil and gas, and 2% wood waste as of Dec. 31, 2022. Slightly mitigating this risk is the company’s accelerated coal retirement plan for its utility, which includes a goal to be coal-free by 2025 and have 90% of its capacity portfolio sourced from clean energy resources by 2040.

Rating Component Scores

Foreign currency issuer credit rating	BBB+/Stable/A-2
Local currency issuer credit rating	BBB+/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-
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	Negative (-1 notch)
Stand-alone credit profile	bbb+

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
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- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
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- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

S&P Global
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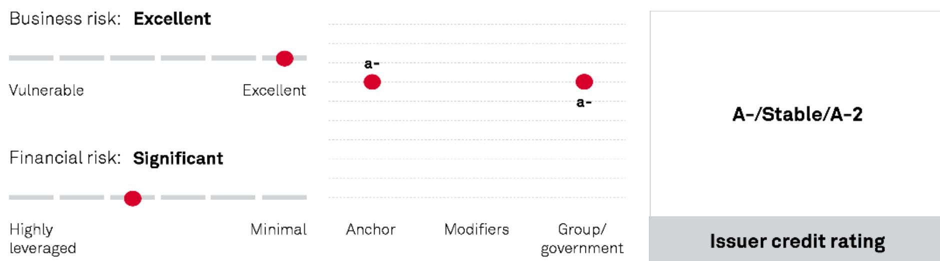
Consumers Energy Co.

July 25, 2022

Ratings Score Snapshot



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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, partially mitigated by a plan to exit coal by 2025.
Sufficient insulating measures for higher rating than group credit profile.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.

The Michigan Public Service Commission (MPSC) recently approved Consumers Energy Co.'s (CE's) gas rate case settlement agreement. The settlement approves a $170 million revenue increase, premised on a 9.9% return on equity (ROE), and it goes into effect on Oct. 1, 2022. CE had initially filed for a $278.4 million revenue increase in December 2021 based on an ROE of 10.5%, which the company later revised to $233 million based on a ROE of 10.25%. This approval includes the revenue decoupling mechanism that was approved in previous rate cases. However, this outcome was slightly offset by the agreement to write off capital expenditures, net of insurance proceeds tied to the repairs associated with the 2019 Ray compressor station fire.

Following a less-than-favorable outcome in its most recent electric rate case, CE filed another rate case increase request with the MPSC for its electric division in April 2022. The company is seeking a $266.4 million rate increase based on a 10.25% ROE. The outcome of this rate case is pending, and we continue to monitor related developments.

CE plans to exit coal by 2025. The company's integrated resource plan (IRP) targets to exit coal by 2025 and substantially reduce dependence on generation from natural gas.

The company's elevated capital spending plan prioritizes infrastructure upgrades and energy transition plans. Over the next five years, CE plans to spend about $14.3 billion to maintain and upgrade its gas infrastructure and electric distribution systems and reduce its carbon emission. The capital plan includes investment of about $6 billion in the gas segment and about $8 billion in the electric segment.

As of 31 March 2022, CE's capacity portfolio consisted of 26% natural gas,18% coal and 11% oil/gas. The company intends to reduce its carbon exposure in line with its IRP, which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 for the electric division and eliminate coal-sourced electric generation by 2025.

We expect CE will continue to effectively manage regulatory risk, in line with the company's business risk profile. We view Michigan's regulatory construct as above average compared to peers because of the benefit of a streamlined 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.

We expect CE's credit measures to remain in the middle of the range for its financial risk profile category. We expect funds from operations (FFO) to debt of about 19%-21% over the next three years.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of about 20%.

Downside scenario

We could lower our rating on Consumers Energy if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or
- We could also lower our rating on Consumers Energy if we lower our rating on parent CMS Energy Corp.

Upside scenario

Although less likely, we could raise our rating on Consumer's Energy if we raise our rating on CMS Energy and Consumer's Energy's stand-alone financial measures improve, reflecting FFO to debt 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 about $2.4 billion annually;
- Annual dividends averaging about $800 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

Consumers Energy Co.--Key Metrics

Mil. $	2021a	2022e	2023f
FFO to debt (%)	21.7	19-20	19-20
Debt to EBITDA (x)	3.9	4-5	4-5
FFO interest coverage (x)	6.4	6-7	6-7

a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE'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

Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Alliant Energy Corp.	Ameren Corp.	WEC Energy Group Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2021-12-31	2021-12-31	2021-12-31	2021-12-31	2021-12-31
Mil.	$	$	$	$	$
Revenue	6,987	5,809	3,669	6,394	8,316
EBITDA	2,406	2,596	1,473	2,663	3,033
Funds from operations (FFO)	2,041	2,256	1,190	2,201	2,490
Interest	380	504	285	434	530
Cash interest paid	375	335	280	464	510
Operating cash flow (OCF)	2,014	1,273	574	1,611	2,071
Capital expenditure	2,136	3,008	1,162	3,506	2,284
Free operating cash flow (FOCF)	(123)	(1,735)	(588)	(1,896)	(213)
Discretionary cash flow (DCF)	(847)	(2,323)	(1,191)	(2,493)	(1,106)
Cash and short-term investments	22	9	39	8	16
Gross available cash	22	9	39	256	16

Consumers Energy Co.--Peer Comparisons

Debt	9,397	10,115	8,292	13,325	16,339
Equity	9,279	8,903	5,990	9,765	11,348
EBITDA margin (%)	34.4	44.7	40.1	41.6	36.5
Return on capital (%)	6.9	8.0	6.3	6.6	7.4
EBITDA interest coverage (x)	6.3	5.1	5.2	6.1	5.7
FFO cash interest coverage (x)	6.4	7.7	5.3	5.7	5.9
Debt/EBITDA (x)	3.9	3.9	5.6	5.0	5.4
FFO/debt (%)	21.7	22.3	14.4	16.5	15.2
OCF/debt (%)	21.4	12.6	6.9	12.1	12.7
FOCF/debt (%)	(1.3)	(17.2)	(7.1)	(14.2)	(1.3)
DCF/debt (%)	(9.0)	(23.0)	(14.4)	(18.7)	(6.8)

Business Risk

Our assessment of CE's business risk profile reflects the company's lower-risk electric and natural gas utility operations. CE is a larger-than-average utility that serves about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan. About 80% of the company's electric customer revenue base is residential and commercial, providing stable cash flow and mitigating CE's exposure to industrial cyclicality. CE is a wholly owned subsidiary of CMS Energy and contributes about 95% of CMS Energy's consolidated operations.

The MPSC regulates CE. 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 streamlined 10-month rate case process. CE 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 nonfuel revenues with the revenues approved by the MPSC. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag.

Financial Risk

We assess CE'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 around $2.8 billion annually over the forecast period. 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.

Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2016	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021
Reporting period	2016a	2017a	2018a	2019a	2020a	2021a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,030	6,187	6,430	6,341	6,155	6,987
EBITDA	2,168	2,267	2,152	2,252	2,392	2,406
Funds from operations (FFO)	1,820	1,954	1,665	1,823	1,968	2,041
Interest expense	333	347	355	335	393	380

Consumers Energy Co.--Financial Summary

Cash interest paid	298	314	331	296	373	375
Operating cash flow (OCF)	1,768	1,792	1,533	1,688	1,265	2,014
Capital expenditure	1,754	1,721	1,920	2,191	2,254	2,136
Free operating cash flow (FOCF)	15	71	(387)	(502)	(989)	(123)
Discretionary cash flow (DCF)	(486)	(453)	(918)	(1,094)	(1,628)	(847)
Cash and short-term investments	131	44	39	11	20	22
Gross available cash	131	44	39	11	20	22
Debt	6,734	7,037	7,774	8,238	9,113	9,397
Common equity	5,939	6,488	6,920	7,737	8,556	9,279
Adjusted ratios						
EBITDA margin (%)	36.0	36.6	33.5	35.5	38.9	34.4
Return on capital (%)	9.7	9.8	7.9	7.7	7.5	6.9
EBITDA interest coverage (x)	6.5	6.5	6.1	6.7	6.1	6.3
FFO cash interest coverage (x)	7.1	7.2	6.0	7.2	6.3	6.4
Debt/EBITDA (x)	3.1	3.1	3.6	3.7	3.8	3.9
FFO/debt (%)	27.0	27.8	21.4	22.1	21.6	21.7
OCF/debt (%)	26.3	25.5	19.7	20.5	13.9	21.4
FOCF/debt (%)	0.2	1.0	(5.0)	(6.1)	(10.9)	(1.3)
DCF/debt (%)	(7.2)	(6.4)	(11.8)	(13.3)	(17.9)	(9.0)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2021									
Company reported amounts	8,810	9,279	7,021	2,252	1,175	311	2,406	1,982	724	2,052
Cash taxes paid	-	-	-	-	-	-	10	-	-	-
Cash interest paid	-	-	-	-	-	-	(330)	-	-	-
Lease liabilities	74	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	8	2	2	(2)	6	-	-
Accessible cash and liquid investments	(22)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	3	(3)	(3)	-	(3)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Share-based compensation expense	-	-	-	21	-	-	-	-	-	-
Securitized stranded costs	(198)	-	(34)	(34)	(7)	(7)	7	(27)	-	-
Power purchase agreements	647	-	-	135	47	47	(47)	87	-	87
Asset-retirement obligations	478	-	-	24	24	24	-	-	-	-
Nonoperating income (expense)	-	-	-	-	5	-	-	-	-	-
Reclassification of interest and dividend cash flows	-	-	-	-	-	-	-	(32)	-	-
Debt: other	(392)	-	-	-	-	-	-	-	-	-
Total adjustments	587	-	(34)	154	71	69	(365)	32	-	84
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	9,397	9,279	6,987	2,406	1,246	380	2,041	2,014	724	2,136

Liquidity

As of March 31, 2022, we assessed CE's liquidity as adequate to cover its needs over the following 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 CE's sound relationships with banks, satisfactory standing in the credit markets, and generally prudent risk management.

Principal liquidity sources

- Cash FFO of about $2 billion;
- Credit facilities of about $1.1 billion; and
- Available cash of about $12 million as of March 31, 2022.

Principal liquidity uses

- Debt maturities of about $365 million as of Mar. 31, 2022;
- Estimated capital spending of about $2.3 billion; and
- Dividends of about $760 million.

Environmental, Social, And Governance

ESG Credit Indicators

E-1	E-2	**E-3**	E-4	E-5

S-1	**S-2**	S-3	S-4	S-5

G-1	**G-2**	G-3	G-4	G-5

- Climate transition risks	- N/A	- N/A

N/A--Not applicable. ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1 - 5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicator Definitions And Applications," published Oct. 13, 2021.

Environmental factors are a moderately negative consideration in our credit rating analysis of CE. The company's use of above-average fossil fuel generation sources exposes it to heightened climate transition risk. The utility's generation capacity portfolio consists of 26% natural gas, 18% coal, 14% renewables, 11% oil/gas, and 8% nuclear as of March 31, 2022. Slightly mitigating this risk is the utility's accelerated coal retirement plan, which includes a goal to be coal-free by 2025 and have 60% of its capacity portfolio sourced from renewables by 2040.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy because we view the utility as integral to the group's identity, highly unlikely to be sold 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 CE 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 are:

- CE 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.
- CE 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.
- CE 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 CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE 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 CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

As of Dec. 31, 2021, CE'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 CE on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- 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 that qualify for a recovery rating as defined in our criteria.
- CE'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.

Rating Component Scores

Foreign currency issuer credit rating	**A-/Stable/A-2**
Local currency 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-**
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: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- 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
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, 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: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of July 25, 2022)*

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-
Preferred Stock	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
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CREDIT OPINION
31 May 2023

Update

Send Your Feedback

Consumers Energy Company

Update to credit analysis

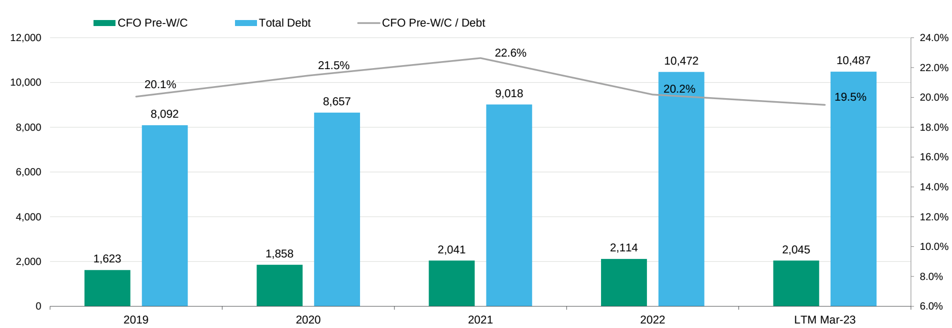
Summary

Consumers Energy Company's (Consumers Energy) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in the credit supportive regulatory environment of Michigan. We expect the utility to maintain a stable financial profile with cash flow from operations before changes in working capital (CFO pre-WC) to debt averaging around 21%, including an adjustment to exclude securitization debt, over the next 2-3 years. At the end of the latest twelve month (LTM) period ending 31 March 2023, Consumers Energy's CFO pre-WC to debt ratio was 20.5%, including the adjustment to exclude securitization bonds. It will continue to execute its robust capital investment plan and will have an active regulatory calendar over this period. Based on the Michigan regulatory framework, we expect the utility to recover its investment costs on a timely basis and to earn an appropriate return on its investments.

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). However, CMS has made notable progress in reducing the percentage of parent debt in its capital structure over the last 2-3 years. We now estimate that the percentage of parent debt will remain around mid-20% of total consolidated debt. All of Consumer Energy's outstanding debt obligations are secured.

Exhibit 1

Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 23.1%, 20.5% and 19.8% in 2021, 2022 and LTM ending 31 March 2023, respectively.
Source: Moody's Financial Metrics

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	(P)A3
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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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Credit strengths

» Credit supportive regulatory environment in Michigan

» Transparent and timely cost recovery

» Stable financial profile

Credit challenges

» Robust capital investment plan

» Maintaining regulatory support for these capital investments

» Lack of geographic and regulatory diversity with single state service territory

Rating outlook

The stable outlook reflects our expectation that financial metrics will remain stable 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 the parent 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 remains above 21% on a sustained basis. In addition, if the Michigan regulatory framework becomes even more formulaic, transparent or timely with its suite of cost 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

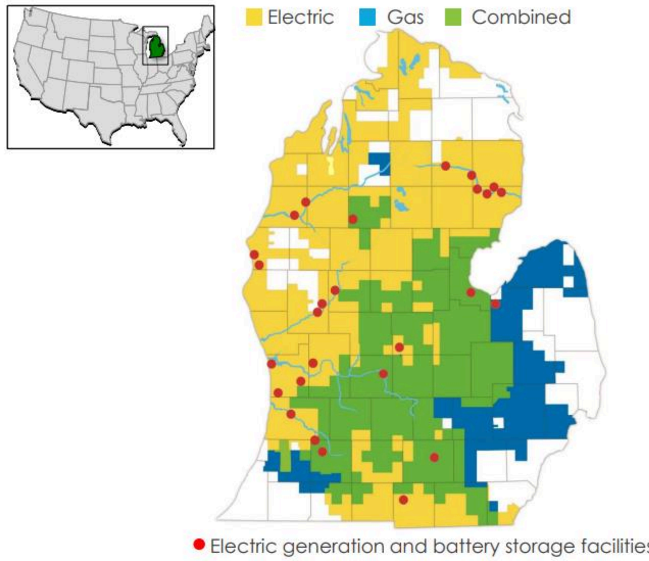
	Dec-19	Dec-20	Dec-21	Dec-22	LTM Mar-23
CFO Pre-W/C + Interest / Interest	6.2x	6.6x	7.5x	7.2x	6.6x
CFO Pre-W/C / Debt	20.1%	21.5%	22.6%	20.2%	19.5%
CFO Pre-W/C – Dividends / Debt	12.7%	14.1%	14.6%	12.8%	12.0%
Debt / Capitalization	46.0%	44.9%	43.7%	45.1%	45.0%

All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Credit metrics included in the exhibit include securitization bonds. When we adjust total debt to exclude securitization debt, Consumers' CFO pre-WC/debt would be 23.1%, 20.5% and 19.8% in 2021, 2022 and LTM ending 31 March 2023, respectively.
Source: Moody's Financial Metrics

Profile

Consumers Energy is a vertically integrated electric and gas utility serving approximately 1.9 million electric and 1.8 million gas customers in the state of Michigan with an average rate base of $22.5 billion in 2022. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. The utility is a wholly-owned subsidiary of CMS and as the primary subsidiary of the parent company, it represents over 95% of CMS's consolidated earnings. In addition to Consumers Energy, CMS has a subsidiary called NorthStar Clean Energy, a non-utility domestic independent power producer and marketer.

Exhibit 3
Consumers Energy's Service Territory



Source: Company Presentations

Detailed credit considerations

Credit supportive regulatory environment

Consumers Energy is regulated by the Michigan Public Service Commission (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 has been 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 costs, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before the construction of major projects. The legislation also lowered the threshold for major projects to $100 million from $500 million, allowing the project approval process to be more efficient.

On 20 April 2022, Consumers Energy and key stakeholders in Michigan reached a settlement related to the company's latest IRP. The settlement included the retirement of all of its remaining coal power plants (all three units at the Campbell power plant site) by 2025, in addition to two units at the Karn coal power plant already scheduled to close in 2023 as a result of the 2018 IRP. Consumers Energy will be able to record approximately $1.2 billion of the remaining book value of these power plants as a regulatory asset and earn a 9% return on equity (ROE) through the remaining life. Instead of securitizing the remaining book value, the settlement will minimize the impact of the accelerated coal retirement on Consumers Energy's credit metrics. We view this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

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 increase sharply.

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. The company's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing approximately 293 miles of cast iron pipe and other high-risk components.

Active rate case filing cadence to be maintained

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. The utility currently has both electric and gas rate cases pending before the MPSC. Over the last three years, Consumers Energy experienced downward pressure on its allowed ROE in its electric and gas rate case outcomes with both electric and gas operations now at a 9.9% ROE. We expect Consumers Energy to maintain a stable financial profile because there are other offsetting mechanisms such as usage of forward test year to allow the utility to earn appropriate returns and to recover investment costs on a timely basis. However, further deterioration of the allowed ROE is likely to put negative pressure on the company's overall financial profile.

On 1 May 2023, Consumers Energy filed an electric rate case, requesting a $216 million base rate increase. The proposed increase was based on a 10.25% ROE and a test year ending 28 February 2025. The pending rate case is expected to conclude in early 2024. In the last electric rate case, Consumers Energy reached an uncontested settlement with several parties and the MPSC issued an order in January 2023 approving the settlement effective 20 January 2023. Under the approved settlement, which resulted in an annual rate increase of $161 million including the $6 million distribution deferral surcharge, Consumers Energy applies a 9.9% ROE and 50.75% permanent capital structure on a regulatory basis with its rate base valued around $13.38 billion.

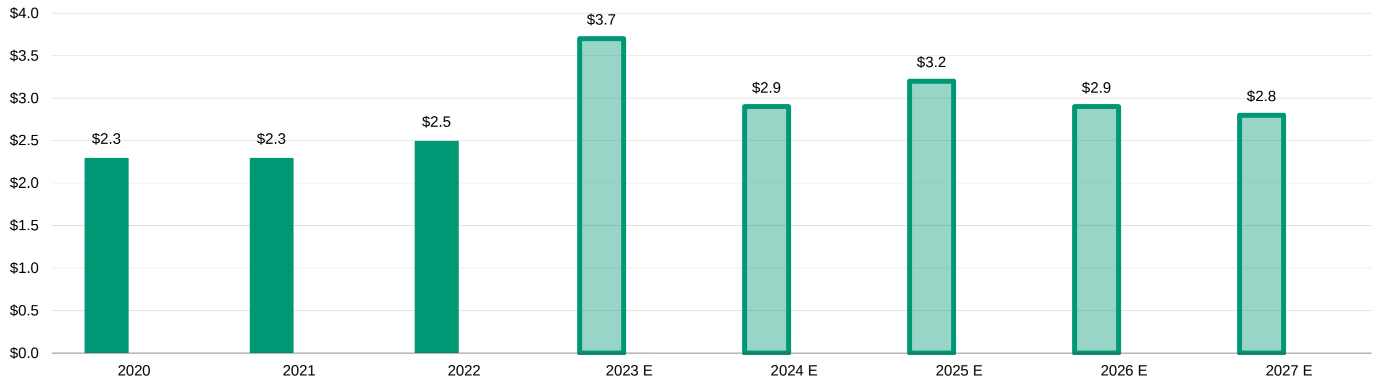
On 15 December 2022, the utility filed a gas rate case, seeking a $212 million increase based on a projected test year for the 12-month period ending 30 September 2024, requesting a 10.25% ROE, 51.5% equity capital structure and a rate base value estimated around $10.34 billion. In April 2023, the MPSC Staff recommended an $89 million increase based on a 9.7% ROE, 50.5% equity capital structure and a $10.15 billion rate base value. A final decision is expected by 16 October 2023.

Stable credit metrics expected to be maintained through its high capital investment cycle

Consumers Energy's capital spending continues to be robust as it is currently in the midst of a large capital investment plan. The company increased its five-year capital expenditure plan through 2027 to $15.5 billion, approximately $1.2 billion higher than the previous plan. Over the next five years, Consumers Energy will invest approximately $12.4 billion primarily to maintain and update its electric distribution system, Covert acquisition and other investment ($6.1 billion) and gas infrastructure ($6.3 billion). These investments should enhance the company's reliability and safety as well as help it execute its clean energy transition plan. In addition, Consumers will invest approximately $3.1 billion in clean generation, which will include investments in wind, solar and hydro electric generation sources.

Exhibit 4

Consumers Energy's elevated capital program will extend through 2027
$ billions

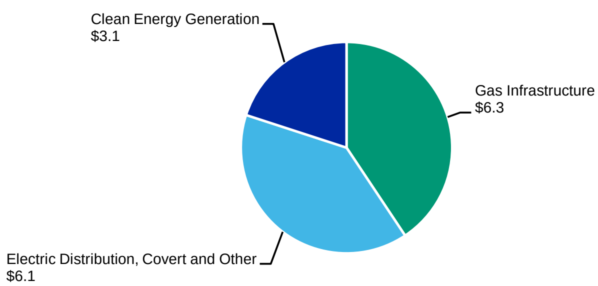


Source: Company Investor Presentation

Through this period, Consumers Energy plans to keep rate increases modest, which should help to maintain regulatory support for investment cost recovery. Funding for these investments will be provided by internally generated cash flow, the issuance of debt at Consumers Energy and equity contributions from CMS. We expect Consumers Energy to maintain its CFO pre-WC to debt at around 21% on average over the next 2-3 years. At the end of 2022 and for the LTM period ending 30 March 2023, Consumers Energy produced a CFO pre-W/C to debt ratio of 20.5% and 19.8%, respectively, excluding securitization debt. The company's ratio was negatively impacted by the under-recovery of PSCR when fuel prices for its electric generation increased significantly in 2022. Consumers is authorized to recover the 2022 under-recovery over three years starting in 2023. Our expectation of the company's financial profile incorporates the impact of this under-recovery and the subsequent recovery over three years.

Exhibit 5

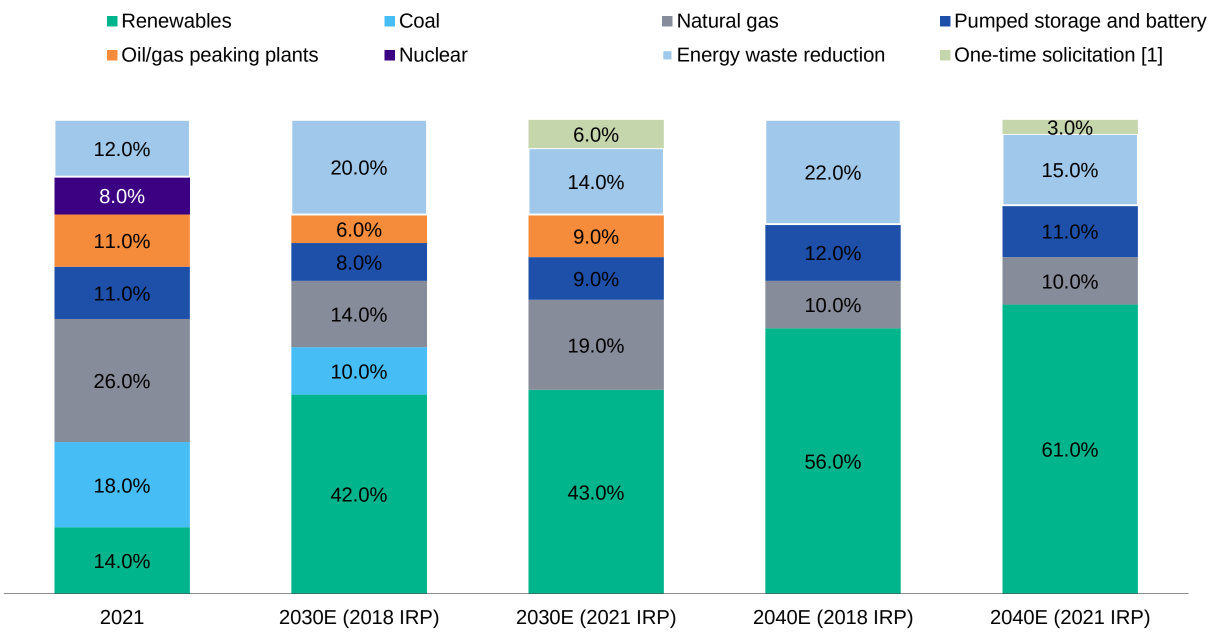
Planned Capital Expenditures 2023 - 2027
$ billions



Source: Company 10K

Based on Consumers' latest IRP approved in 2022, the utility will add up to 8 GW of solar power, which is 2 GW more than what was approved in the company's 2018 IRP. As a result, by 2040, more than 60% of Consumer Energy's generation capacity will be from renewable sources. In order to replace the retiring coal capacity, the utility agreed to acquire the Covert natural gas-fired power plant for approximately $815 million in 2023. It will also issue requests for proposals (RFP) in 2025 for two purchased power agreements (PPA) for 500 MW of dispatchable generation and 200 MW of clean energy sources.

Exhibit 6
Based on the latest IRP settlement, more than 60% of Consumers Energy's generation sources will be renewables by 2040



[1] One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.
Source: Company's 10-K in 2022 and 2021, and latest investor presentation

ESG considerations

Consumers Energy's ESG Credit Impact Score is CIS-3 (Moderately Negative)

Exhibit 7
ESG Credit Impact Score

CIS-3

Moderately Negative

For an issuer scored CIS-3 (Moderately Negative), its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The negative influence of the overall ESG attributes on the rating is more pronounced compared to an issuer scored CIS-2.

Source: Moody's Investors Service

Consumers Energy's ESG Credit Impact Score (**CIS-3**) reflects moderately negative environmental risk from some exposure to physical climate risk and moderating carbon transition risk. It also incorporates social risks stemming from inherent risk associated with regulated utilities and governance risk that is not a material driver.

Exhibit 8
ESG Issuer Profile Scores

ENVIRONMENTAL	SOCIAL	GOVERNANCE
E-3	S-3	G-2
Moderately Negative	Moderately Negative	Neutral-to-Low

Source: Moody's Investors Service

Environmental
Consumers Energy's ESG attributes reflect the company's moderating environmental risk (**E-3** issuer profile score). The company is better positioned for the carbon transition with strategies and plans in place that substantially mitigate its carbon transition exposure. The utility is currently in a transition to phase out its coal-fired generation and targets zero coal-fired generation output by 2025, accelerated from its prior target of 2039. The utility also established a goal of net zero methane emission for its gas delivery system by 2030 and net zero greenhouse gas emissions for its entire natural gas system, including customer and supplier emissions, by 2050. Michigan's regulatory framework supports the utility's transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Social
Social risk (**S-3** issuer profile score) for Consumers Energy is primarily related to its customer and regulatory relations as well as demographic and societal trends. The utility'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 important social considerations.

Governance
As a subsidiary of CMS, corporate governance considerations include the financial policy and risk management of its parent company. Consumers Energy's governance does not pose a particular risk (**G-2** issuer profile score) and is not a material driver in the company's overall credit profile.

ESG Issuer Profile Scores and Credit Impact Scores for Consumers Energy are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for Consumers Energy on MDC and view the ESG Scores section.

Liquidity analysis
We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumers Energy's external liquidity sources include a $1.1 billion secured revolving credit facility expiring in December 2027 and, as of 31 December 2022, net availability was $1.071 billion with $29 million of letters of credit outstanding. Consumers Energy also maintains a $250 million secured credit facility terminating in November 2024 and had $223 million available at the end of 2022. Both facilities are secured by first mortgage bonds. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's $500 million commercial paper program. At 31 December 2022, the company had $20 million of commercial paper notes outstanding under the 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 65%. At 31 December 2022, debt to capital was 50%.

These facilities includes a sustainability linked pricing metrics, which permits pricing adjustments for meeting targets related to sustainability. Targets include renewable generation and diverse supplier spend, highlighting its commitment to shifting its exposure to a greater renewable content and to supplier diversity.

The utility's continuing capital expenditure program and dividend policy will 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 LTM period ended 31 March 2023, Consumers generated approximately $1.3 billion of cash from operations, invested $2.3 billion and distributed $782 million of dividends to CMS, resulting in negative free cash flow of approximately $1.8 billion.

Over the last twelve months, Consumers completed four first mortgage bond issuances with total proceeds of $1.95 billion, including $425 million notes due March 2028 and $700 million notes due May 2033.

Appendix

Exhibit 9

Cash Flow and Credit Metrics

CF Metrics	Dec-19	Dec-20	Dec-21	Dec-22	LTM Mar-23
As Adjusted					
FFO	**1,752**	**1,994**	**2,054**	**2,125**	**1,976**
+/- Other	-129	-136	-13	-11	69
CFO Pre-WC	**1,623**	**1,858**	**2,041**	**2,114**	**2,045**
+/- ΔWC	-15	25	-53	-1,116	-722
CFO	**1,608**	**1,883**	**1,988**	**998**	**1,323**
- Div	593	638	723	770	782
- Capex	2,100	2,184	2,066	2,256	2,305
FCF	**-1,085**	**-939**	**-801**	**-2,028**	**-1,764**
(CFO Pre-W/C) / Debt	20.1%	21.5%	22.6%	20.2%	19.5%
(CFO Pre-W/C - Dividends) / Debt	12.7%	14.1%	14.6%	12.8%	12.0%
FFO / Debt	21.6%	23.0%	22.8%	20.3%	18.8%
RCF / Debt	14.3%	15.7%	14.8%	12.9%	11.4%
Revenue	6,376	6,189	7,021	8,151	8,078
Interest Expense	312	332	315	342	366
Net Income	725	798	838	883	728
Total Assets	23,699	25,399	27,140	29,916	29,772
Total Liabilities	16,053	16,862	17,880	19,780	19,616
Total Equity	7,647	8,538	9,261	10,137	10,157

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

	Consumers Energy Company (P)A3 (Stable)			DTE Electric Company A2 (Stable)			DTE Gas Company A3 (Stable)			Northern States Power Company (Minnesota) A2 (Stable)			Wisconsin Power and Light Company A3 (Negative)		
(In US millions)	FYE Dec-21	FYE Dec-22	LTM Mar-23	FYE Dec-21	FYE Dec-22	LTM Mar-23	FYE Dec-21	FYE Dec-22	LTM Mar-23	FYE Dec-22	FYE Dec-22	LTM Mar-23	FYE Dec-21	FYE Dec-22	LTM Mar-23
Revenue	7,021	8,151	8,078	5,809	6,397	6,286	1,532	1,894	1,894	5,756	6,684	6,652	1,523	1,856	1,866
CFO Pre-W/C	2,041	2,114	2,045	2,348	2,164	2,290	393	575	575	1,054	2,034	2,091	377	339	341
Total Debt	9,018	10,472	10,487	9,916	11,408	11,322	2,310	2,602	2,602	6,832	7,292	7,505	2,819	3,323	3,390
CFO Pre-W/C + Interest / Interest	7.5x	7.2x	6.6x	7.5x	6.5x	6.6x	5.8x	7.2x	7.2x	5.0x	8.2x	8.2x	4.9x	4.8x	4.7x
CFO Pre-W/C / Debt	22.6%	20.2%	19.5%	23.7%	19.0%	20.2%	17.0%	22.1%	22.1%	15.4%	27.9%	27.9%	13.4%	10.2%	10.1%
CFO Pre-W/C – Dividends / Debt	14.6%	12.8%	12.0%	17.8%	12.3%	14.3%	10.6%	15.8%	15.8%	9.1%	20.2%	20.7%	7.4%	4.9%	4.8%
Debt / Capitalization	43.7%	45.1%	45.0%	46.0%	47.4%	47.3%	43.5%	44.5%	44.5%	41.8%	43.4%	43.8%	44.1%	43.8%	43.0%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End.
Source: Moody's Financial Metrics

Rating methodology and scorecard factors

Exhibit 11

Methodology Scoring Factors

Consumers Energy Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2023		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)	7.1x	Aa	6x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	22.4%	A	20% - 22%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	14.4%	Baa	13% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	43.3%	A	43% - 47%	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)A3

* 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 3/31/2023.

[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

Ratings

Exhibit 12

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
LT IRB/PC	A3
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
Pref. Stock	Ba1

Source: Moody's Investors Service

REPORT NUMBER 1368360

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

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
24 May 2022

Update

Send Your Feedback

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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EMEA	44-20-7772-5454

Consumers Energy Company

Update to credit analysis

Summary

Consumers Energy Company's (Consumers Energy) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in the credit supportive regulatory environment of Michigan. We expect Consumers Energy to maintain a stable financial profile with its cash flow from operations before changes in working capital (CFO pre-WC) to debt averaging 21% to 23% over the next 12-18 months. At the end of 2021, Consumers Energy's CFO pre-WC to debt was 22.6%. Consumers will continue executing on its robust capital investment plan and have an active regulatory calendar over this period. Based on the Michigan regulatory framework, we expect Consumers Energy to recover its investment costs on a timely basis and to earn an appropriate return on its investments.

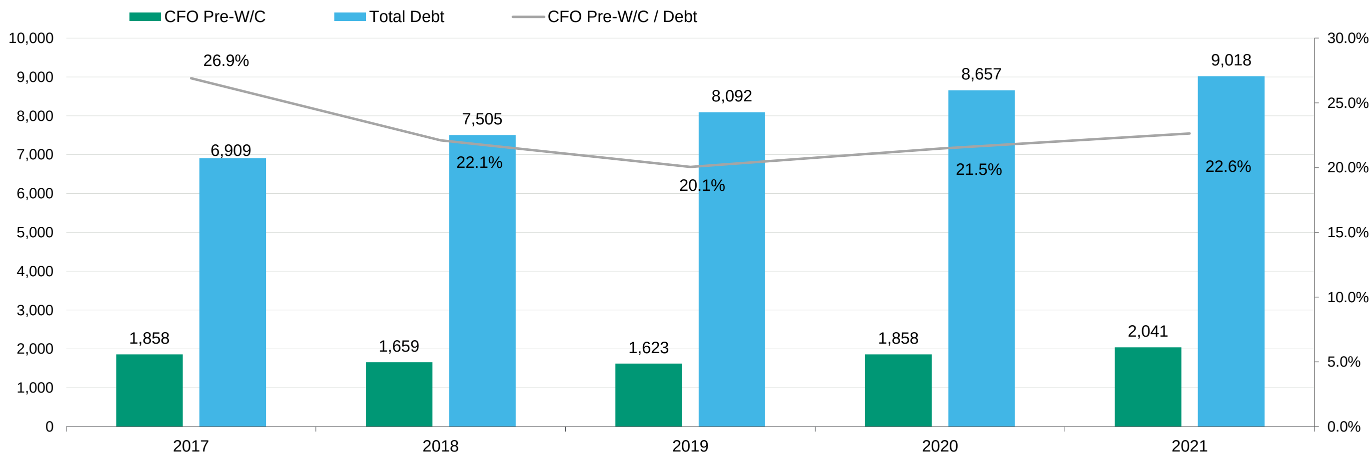
Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). CMS has made progress in reducing consolidated leverage as well as the percentage of parent debt in its capital structure. All of Consumer Energy's outstanding debt obligations are secured.

Recent developments

On 20 April 2022, Consumers Energy announced that the company and key stakeholders in Michigan had reached a settlement related to the company's latest integrated resource plan (IRP), filed with the Michigan Public Service Commission (MPSC) in June 2021. The settlement agreement is now before the MPSC for final approval. We view the settlement to be constructive and evidence of continued credit support in Michigan.

Consumers Energy remains active with its rate case filings. Consumers Energy updated its general electric rate increase request to $233 million on 29 April 2022 based on a 10.25% return on equity (ROE). In December 2021, the utility filed a gas rate case, requesting $278 million rate increase based on a 10.5% ROE.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



Source: Moody's Financial Metrics

Credit strengths

» Credit supportive regulatory environment

» Transparent and timely cost recovery

» Stable financial profile

Credit challenges

» Robust capital investment plan

» Maintaining regulatory support for this spending

» High leverage at the parent company

Rating outlook

The stable outlook reflects our expectation that financial metrics will remain stable 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 remain consistent such that CFO pre-WC to debt remains 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

Consumers Energy Company Key Indicators

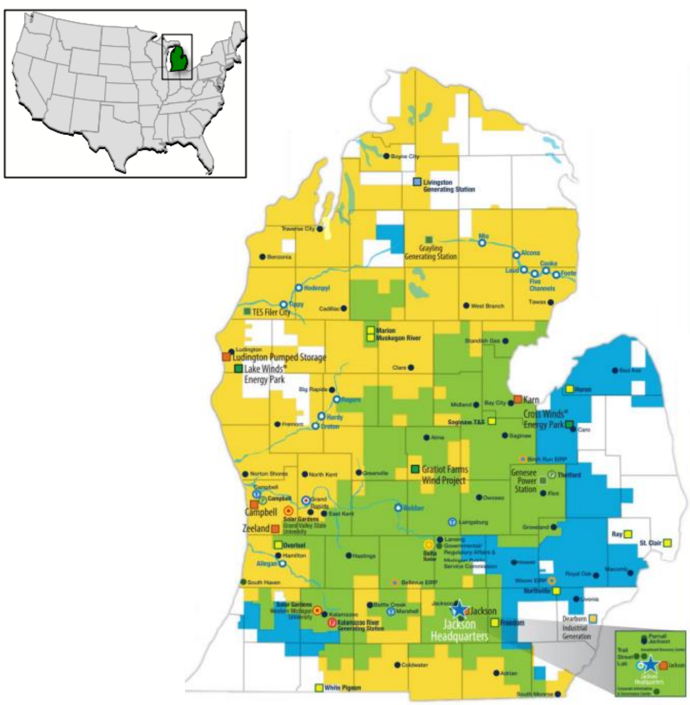
	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21
CFO Pre-W/C + Interest / Interest	7.5x	6.3x	6.2x	6.6x	7.5x
CFO Pre-W/C / Debt	26.9%	22.1%	20.1%	21.5%	22.6%
CFO Pre-W/C – Dividends / Debt	19.3%	15.0%	12.7%	14.1%	14.6%
Debt / Capitalization	46.1%	46.4%	46.0%	44.9%	43.7%

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 is a vertically integrated electric and gas utility serving approximately 6.8 million customers in the state of Michigan with a rate base over $21 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, representing over 9% of its consolidated earnings. In addition to Consumers Energy, CMS owns approximately 1,483 gross MW of unregulated, primarily natural gas-fired, generation located mostly within Michigan. 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

Credit supportive regulatory environment

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, allowing the project approval process to be more efficient.

On 20 April 2022, Consumers Energy and key stakeholders in Michigan reached a settlement related to the company's latest IRP, filed with the MPSC in June 2021. The settlement includes the retirement of all of its remaining coal power plants (all three units at the Campbell power plant site) by 2025, in addition to two units at the Karn coal power plant already scheduled to close in 2023 as a result of the 2018 IRP. Consumers will be able to record approximately $1.2 billion of the remaining book value of these power plants as a regulatory asset and earn a 9% return on equity (ROE) through the remaining life. Instead of securitizing the remaining book value, the settlement will minimize the impact of the accelerated coal retirement on Consumers' credit metrics. We view this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

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 293 miles of cast iron pipe and other high-risk components. In its current gas rate case, Consumers Energy's EIRP request is about $332 million for the test year between 1 October 2022 and 30 September 2023.

Annual rate case filing cadence to be maintained

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. The utility currently has both electric and gas rate cases pending before the MPSC. Over the last three years, Consumers Energy experienced downward pressure on the allowed ROE in its electric and gas rate case outcomes with both electric and gas operations now at a 9.9% ROE. However, we expect Consumers Energy to maintain a stable financial profile because there are other offsetting mechanisms such as usage of forward test year to allow the utility to earn appropriate returns on its investment and to recover investment costs on a timely basis.

On 28 April 2022, Consumers Energy filed its latest electric rate case, requesting a $233 million base rate increase based on a 10.25% ROE and $13.75 billion rate base. The final order from the MPSC is expected in the first quarter of 2023. The utility also has a gas rate case pending, having filed for a $278 million rate increase in December 2021. In April 2022, the MPSC staff recommended a rate increase of $172 million based on a 9.6% ROE. The largest difference between the company's request and the staff recommendation is mostly due to the different ROE levels in their respective filings. The MPSC final order is expected in October 2022.

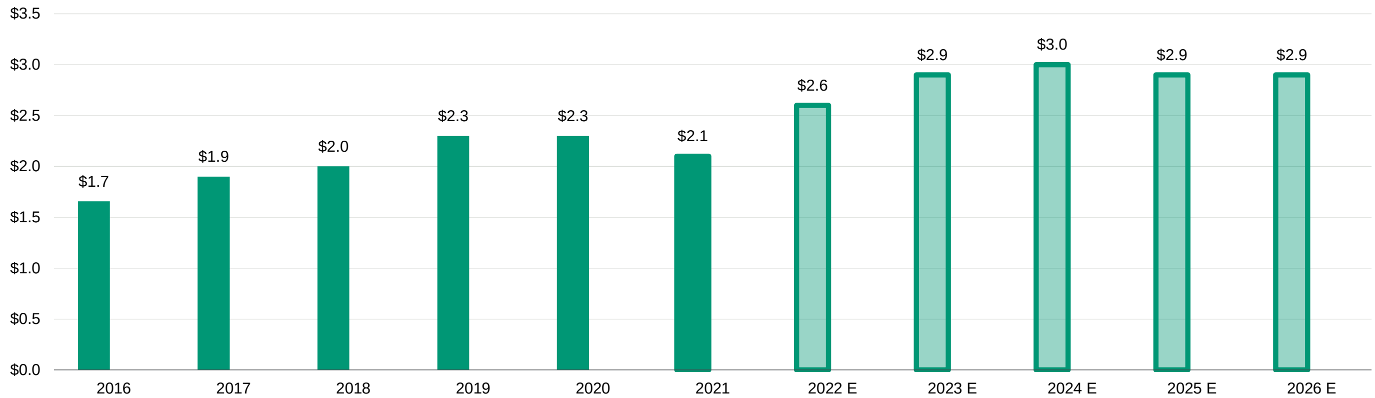
Stable credit metrics expected through high capital investment cycle

Consumers' capital investment continues to be robust as it is currently in the midst of a large capital investment plan with total estimated investment to be approximately $14.3 billion from 2022 through 2026. 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 2022, projected investments are approximately $2.6 billion compared to around $2.1 billion in 2021, $2.3 billion in 2020, and $2.3 billion in 2019, as shown below. Based on the 2021 IRP, Consumers will add approximately $1 billion of incremental capital investment.

Exhibit 4

Consumers Energy's elevated capital program will extend through 2026

$ billions



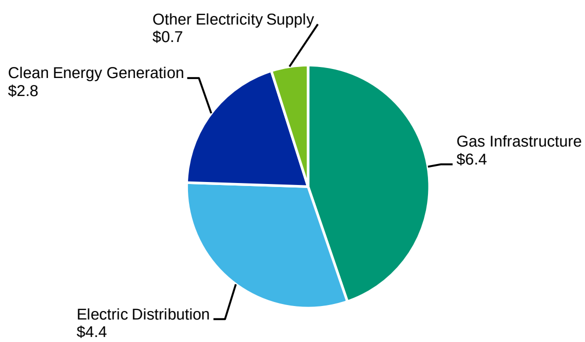
Source: Company Investor Presentation

Over the 2022-2026 period, projected capital investments will include maintenance capital of about $10.8 billion (approximately $4.4 billion for electric operations and $6.4 billion for gas utility operations), $2.8 billion for clean energy generation and $700 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 Energy and equity contributions from CMS. We expect Consumers Energy to maintain its CFO pre-WC to debt between 21% and 23% over the next 12-18 months. At the end of 2021, Consumers Energy produced a ratio of 22.6%.

Exhibit 5

Planned Capital Expenditures 2022 - 2026

$ billions



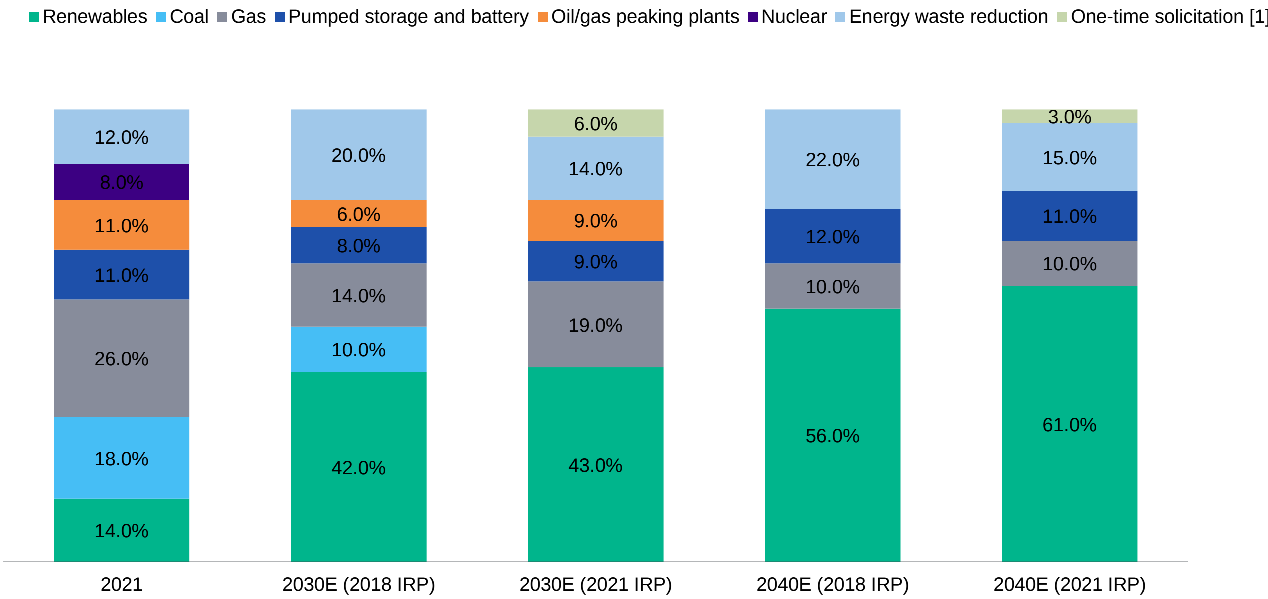
This does not include the additional capital investment planned under the 2021 IRP

Source: Company 10K

Through 2040, Consumers Energy will add up to 8 GW of solar power, which is 2 GW more than what was approved in the company's 2018 IRP. As a result, by 2040, more than 60% of Consumer Energy's generation capacity will be from renewable sources. In order to replace the retiring coal capacity, the utility agreed to acquire the Covert natural gas-fired power plant for approximately $815 million in 2023. It will also issue request for proposals (RFP) in 2025 for two purchased power agreements (PPA). The PPAs must be for 500 MW of dispatchable generation and 200 MW of clean energy sources.

Exhibit 6

Based on the latest IRP settlement, more than 60% of Consumers' generation source will be renewables by 2040



[1] One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.
Source: Company's 10-K in 2020 and 2021, and latest investor presentation

ESG considerations

Environmental

We view Consumers Energy's environmental risk to be moderately negative. The company is better positioned for the carbon transition with strategies and plans in place that substantially mitigate its carbon transition exposure. The utility is currently in a transition to phase out its coal-fired generation and targets zero coal-fired generation output by 2025, accelerated from its prior target of 2039. The utility also established a goal of net zero methane emission for its gas delivery system by 2030 and net zero greenhouse gas emissions for its entire natural gas system, including customer and supplier emissions, by 2050. Michigan's regulatory framework supports the utility's transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Social

Social risks are primarily related to Consumers Energy's customer and regulatory relations as well as demographic and societal trends. The utility'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 important social considerations.

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 external liquidity sources include an $850 million secured revolving credit facility expiring in June 2024 and as of 31 December 2021, its net availability was $838 million with $12 million letters of credit outstanding. Consumers Energy also maintains a $250 million secured credit facility terminating in November 2023. As of 31 December 2021, net availability was $242 million with $8 million letters of credit outstanding. Consumers Energy had no commercial paper outstanding and no borrowings under its various external credit facilities.

These facilities 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. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's $500 million commercial paper program. They 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 2021, debt to capital was 48%.

In August and October 2021, Consumers issued $300 million first mortgage bond due in 2052 and $35 million of tax-exempt revenue bonds due in April 2035, 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 2021, Consumers generated approximately $2 billion of cash from operations (CFO), invested $2.1 billion in capital investments and distributed $724 million in dividend payments to CMS, resulting in negative free cash flow (FCF) of approximately $794 million that was offset by parent contributions of $575 million and incremental long-term debt. Consumers' policy is to grow its dividend with earnings, maintaining a payout ratio in the 80% range.

Rating methodology and scorecard factors

Methodology Scoring Factors
Consumers Energy Company

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current FY 12/31/2021		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)	6.8x	Aa	6.8x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	21.4%	Baa	21% - 23%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	13.8%	Baa	13% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	44.8%	A	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 12/31/2021.
[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

CF Metrics	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21
As Adjusted					
FFO	**1,825**	**1,760**	**1,752**	**1,994**	**2,054**
+/- Other	33	-101	-129	-136	-13
CFO Pre-WC	**1,858**	**1,659**	**1,623**	**1,858**	**2,041**
+/- ΔWC	-65	1	-15	25	-53
CFO	**1,793**	**1,660**	**1,608**	**1,883**	**1,988**
- Div	523	532	593	638	723
- Capex	1,649	1,834	2,100	2,184	2,066
FCF	**-379**	**-706**	**-1,085**	**-939**	**-801**
(CFO Pre-W/C) / Debt	26.9%	22.1%	20.1%	21.5%	22.6%
(CFO Pre-W/C - Dividends) / Debt	19.3%	15.0%	12.7%	14.1%	14.6%
FFO / Debt	26.4%	23.5%	21.6%	23.0%	22.8%
RCF / Debt	18.9%	16.4%	14.3%	15.7%	14.8%
Revenue	6,222	6,464	6,376	6,189	7,021
Interest Expense	285	315	312	332	315
Net Income	643	527	725	798	838
Total Assets	21,179	22,096	23,699	25,399	27,140
Total Liabilities	14,746	15,251	16,053	16,862	17,880
Total Equity	6,434	6,845	7,647	8,538	9,261

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

	Consumers Energy Company A1 (Stable)			DTE Electric Company A2 (Stable)			DTE Gas Company A3 (Stable)			Northern States Power Company (Minnesota) A2 (Stable)			Wisconsin Power and Light Company A3 (Stable)		
(In US millions)	FYE Dec-19	FYE Dec-20	FYE Dec-21	FYE Dec-19	FYE Dec-20	FYE Dec-21	FYE Dec-19	FYE Dec-20	FYE Dec-21	FYE Dec-20	FYE Dec-20	FYE Dec-21	FYE Dec-20	FYE Dec-21	LTM Mar-22
Revenue	6,376	6,189	7,021	5,224	5,506	5,809	1,462	1,396	1,532	5,112	5,101	5,756	1,476	1,395	1,624
CFO Pre-W/C	1,623	1,858	2,041	1,791	1,802	2,071	368	409	393	1,368	1,457	1,054	425	475	418
Total Debt	8,092	8,657	9,018	8,495	9,437	9,916	1,997	2,168	2,310	5,827	6,242	6,832	2,328	2,596	2,741
CFO Pre-W/C + Interest / Interest	6.2x	6.6x	7.5x	6.3x	6.1x	6.8x	5.5x	6.0x	5.8x	6.7x	7.0x	5.0x	6.6x	6.5x	5.6x
CFO Pre-W/C / Debt	20.1%	21.5%	22.6%	21.1%	19.1%	20.9%	18.4%	18.9%	17.0%	23.5%	23.3%	15.4%	18.2%	18.3%	15.2%
CFO Pre-W/C – Dividends / Debt	12.7%	14.1%	14.6%	15.3%	13.4%	15.0%	12.3%	12.6%	10.6%	15.5%	16.8%	9.1%	12.1%	12.1%	9.0%
Debt / Capitalization	46.0%	44.9%	43.7%	47.2%	47.1%	46.0%	44.2%	43.9%	43.5%	42.9%	42.0%	41.8%	44.0%	45.0%	41.9%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End.
Source: Moody's Financial Metrics

Ratings

Exhibit 10

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
LT IRB/PC	A3
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
Pref. Stock	Ba1

Source: Moody's Investors Service

REPORT NUMBER 1328063

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

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Consumers Energy Company

Consumers Energy Company's ratings reflect stability of its predominantly low-risk state-regulated electric and natural gas utility operations, constructive regulatory environment in Michigan and solid financial profile.

Key Rating Drivers

Constructive Regulatory Environment: Fitch Ratings believes the Michigan regulatory environment remains constructive from a credit perspective, as demonstrated by credit-supportive general rate case (GRC) outcomes in recent years. The Michigan Public Service Commission (MPSC) approved an authorized ROE of 9.9% in Consumer Energy's last GRC, which compares favorably with the industry average.

Supportive state legislation and MPSC policies mitigate regulatory lag through the use of a forward test year, a 10-month review period for 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 revenues approved by the MPSC. Fitch does not expect a material negative outcome in the pending audit ordered by MPSC in October 2022 to assess CMS Energy Corporation 's compliance with storm outages and safety regulations. Unexpected deterioration in Michigan rate regulation could result in future adverse rating actions.

Gas Base Rate Case: In December 2022, Consumers Energy filed a gas rate case requesting an annual rate increase of $212 million, based on a 10.25% authorized ROE and projected test year ending September 2024. The filing requests authority to recover costs of upgrading transmission infrastructure, transforming compression and storage operations and replacing aging distribution pipes. Fitch expects a final MPSC decision around October 2023.

Electric Base Rate Case: In April 2022, Consumers Energy filed its electric rate case requesting an annual rate increase of $272 million, based on a 10.25% authorized ROE for a projected test year ending December 2023. The filing requests authority to recover investments associated with distribution system, reliability, solar generation, environmental compliance, enhanced technology and approval of an unrecovered surcharge of $6 million of distribution investments.

Consumers Energy submitted a settlement agreement to the MPSC in December 2022. The settlement, approved in January 2023, increases annual rates by approximately $155 million based on a 9.9% authorized ROE. The common equity ratio is 50.75%

Solid Financial Profile: Fitch believes Consumers Energy's current and projected credit metrics are consistent with the rating. Fitch projects FFO leverage will remain within its sensitivities in 2023–2025, averaging 4.3x. Fitch estimates higher FFO leverage of 4.5x in 2022, reflecting moderate pressure from high capital spending and elevated commodity costs. Debt maturities are manageable, and Fitch expects the company to have continued access to capital markets.

Significant Capex Driven by Decarbonization Plans: Consumers Energy's capital program is elevated at $14.3 billion for 2022–2026, with 45% allocated for gas infrastructure, 36% for electric distribution and supply, and 19% for clean generation. Concerns regarding the large capex plan are mitigated by the MPSC's constructive ratemaking policies and alignment of planned capex with state energy policy. Consumers Energy plans to eliminate coal from its generation mix in 2025, replacing it with low-emitting gas and non-emitting renewable generation facilities.

Ratings

Rating Tpe	Rating	Outlook	Last Rating Action
Long-Term IDR	A–	Stable	Affirmed Jan. 19, 2023
Short-Term IDR	F2		Affirmed Jan. 19, 2023
Senior Secured Debt	A+		Affirmed Jan. 19, 2023
Senior Unsecured Debt	A		Affirmed Jan. 19, 2023
Preferred Stock	BBB+		Affirmed Jan. 19, 2023
CP	F2		Affirmed Jan. 19, 2023

Click here for full list of ratings

Applicable Criteria

Corporate Rating Criteria (October 2022)

Sector Navigators: Addendum to the Corporate Rating Criteria (October 2022)

Parent and Subsidiary Linkage Rating Criteria (December 2021)

Corporates Recovery Ratings and Instrument Ratings Criteria (April 2021)

Corporate Hybrids Treatment and Notching Criteria (November 2020)

Related Research

North American Utilities, Power & Gas Dashboard: Fourth-Quarter 2022 (January 2023)

North American Utilities, Power & Gas Outlook 2023 (December 2022)

U.S. Utilities: Mostly Strong Quarterly Earnings; Bill Affordability in Focus (3Q22 Earnings Wrap-Up) (November 2022)

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Parent-Subsidiary Linkage: There is parent-subsidiary rating linkage between CMS Energy and Consumers Energy. Fitch determines CMS Energy's standalone credit profile (SCP) based upon consolidated metrics. Fitch considers Consumers Energy's SCP to be stronger than CMS Energy's. Emphasis is placed on Consumers Energy's status as a regulated entity. Legal ring-fencing is considered porous given the general protections afforded by economic regulation. Access and control are also evaluated as porous.

CMS Energy centrally manages the treasury function for all of its entities. However, both the parent and Consumers Energy issue their own long-term debt. Due to the aforementioned linkage considerations, Fitch will limit the difference between the Long-Term Issuer Default Ratings (IDRs) of CMS Energy and Consumers Energy to two notches.

Financial Summary

($ Mil., as of Dec. 31)	2018	2019	2020	2021
Gross Revenue	6,430	6,342	6,155	6,987
EBITDA	1,952	2,047	2,187	2,195
Cash Flow from Operations	1,424	1,569	1,186	1,948
Capital Intensity (Capex/Revenue) (%)	28.3	32.9	35.3	29.4
Debt	6,791	7,198	8,318	8,727
FFO Interest Coverage (x)	6.3	7.2	5.1	7.8
FFO Leverage (x)	3.8	3.6	5.4	3.9
EBITDA Leverage (x)	3.5	3.5	3.8	4.0

Source: Fitch Ratings, Fitch Solutions

Rating Derivation Relative to Peers

The credit profile of Consumers Energy is comparable to peers, such as DTE Electric Company (A–/Stable), Northern States Power Company-Minnesota (A–/Stable), Northern States Power Company-Wisconsin (A–/Stable), and Public Service Company of Colorado (A–/Stable). All four are regulated utilities with single-state operations, albeit in constructive environments.

FFO leverage at the electric peers is marginally stronger in the 3.8x–4.1x range. However, it is marginally weaker at DTE Gas Company (BBB+/Stable) at approximately 4.8x. Fitch forecasts FFO leverage to average around 4.3x through 2025 at Consumers Energy.

Rating Sensitivities

Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade

- FFO leverage expected to be less than 3.5x on a sustained basis;
- A positive rating action on Consumers Energy would also require an equally positive rating action on 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 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 Dec. 14, 2027. As of September 2022, CMS Energy had $14 million of LOCs outstanding and no borrowings outstanding, leaving $536 million of availability under its RCF. It also has a fully utilized LOC of $50 million as of Sept. 30, 2022, which terminates in September 2024.

Consumers Energy primarily meets its short-term liquidity needs through the issuance of CP under its $500 million CP program supported by its $1.1 billion RCF, which increased from $850 million in December 2022. Consumers Energy's RCF will mature on Dec. 14, 2027 and is secured by the utility's first mortgage bonds (FMBs). Consumers Energy had no CP borrowings and $29 million of LOCs outstanding as of Sept. 30, 2022, leaving $821 million of unused availability under its RCF.

Consumers Energy has a separate $250 million RCF that will mature on Nov. 19, 2024. This RCF had no borrowings and $62 million of LOCs outstanding at Sept. 30, 2022, leaving $188 million of availability. The facility is also secured by the utility's FMBs.

ESG Considerations

Unless otherwise disclosed in this section, the highest level of ESG credit relevance is a score of '3'. This means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

Liquidity and Debt Maturities

Liquidity Analysis

($ Mil.)	YE 2021	3Q22
Total Cash and Cash Equivalents	44	110
Short-Term Investments	—	—
Less: Not Readily Available Cash and Cash Equivalents	22	27
Fitch-Defined Readily Available Cash and Cash Equivalents	**22**	**83**
Availability Under Committed Lines of Credit	1,080	1,080
Total Liquidity	**1,102**	**1,163**
LTM EBITDA After Associates and Minorities	2,195	2,365
LTM FCF	-828	-1,715

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Scheduled Debt Maturities

($ Mil.)	2021
2022	0
2023	625
2024	852
2025	0
2026	0
Thereafter	7,268
Total	**8,745**

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Key Assumptions

Fitch's Key Assumptions Within Our Rating Case for the Issuer Include

- Periodic rate case filings to recover Consumers Energy's investment in rate base and associated costs;
- Operating cost reductions averaging 2% per year;
- Flat annual electric and natural gas sales growth;
- Total utility capex in line with management's assumptions;
- Dividend growth of 6%–8% per year;
- Normal weather;
- No material equity issuances till 2025 at the parent level, apart from the equity issuances planned during 2023 for the acquisition of the Covert power generation unit by Consumers Energy.

FitchRatings

Financial Data

	Historical			
($ Mil., as of Dec. 31)	2018	2019	2020	2021
Summary Income Statement				
Gross Revenue	6,430	6,342	6,155	6,987
Revenue Growth (%)	3.9	-1.4	-2.9	13.5
EBITDA (Before Income from Associates)	1,952	2,047	2,187	2,195
EBITDA Margin (%)	30.4	32.3	35.5	31.4
EBITDAR	1,963	2,080	2,187	2,195
EBITDAR Margin (%)	30.5	32.8	35.5	31.4
EBIT	1,056	1,104	1,197	1,152
EBIT Margin (%)	16.4	17.4	19.4	16.5
Gross Interest Expense	-283	-275	-296	-291
Pretax Income (Including Associate Income/Loss)	847	928	989	1,024
Summary Balance Sheet				
Readily Available Cash and Equivalents	39	11	20	22
Debt	6,791	7,198	8,318	8,727
Lease-Adjusted Debt	6,879	7,462	8,318	8,727
Net Debt	6,752	7,187	8,298	8,705
Summary Cash Flow Statement				
EBITDA	1,952	2,047	2,187	2,195
Cash Interest Paid	-284	-275	-296	-287
Cash Tax	-156	-132	-51	10
Dividends Received Less Dividends Paid to Minorities (Inflow/[Out]flow)	0	0	0	0
Other Items Before FFO	-11	70	-610	50
Funds Flow from Operations	1,512	1,720	1,239	1,974
FFO Margin (%)	23.5	27.1	20.1	28.3
Change in Working Capital	-88	-151	-53	-26
Cash Flow from Operations (Fitch Defined)	1,424	1,569	1,186	1,948
Total Non-Operating/Nonrecurring Cash Flow	0	0	0	0
Capex	-1,822	-2,085	-2,170	-2,052
Capital Intensity (Capex/Revenue) (%)	28.3	32.9	35.3	29.4
Common Dividends	-533	-594	-639	-724
FCF	-931	-1,110	-1,623	-828
Net Acquisitions and Divestitures	0	77	58	0
Other Investing and Financing Cash Flow Items	-140	-115	-161	-138
Net Debt Proceeds	816	445	1,085	393
Net Equity Proceeds	250	675	650	575
Total Change in Cash	-5	-28	9	2
Leverage Ratios (x)				
EBITDA Net Leverage	3.5	3.5	3.8	4.0
EBITDAR Leverage	3.5	3.6	3.8	4.0
EBITDAR Net Leverage	3.5	3.6	3.8	4.0
EBITDA Leverage	3.5	3.5	3.8	4.0
FFO-Adjusted Leverage	3.8	3.7	5.4	3.9
FFO-Adjusted Net Leverage	3.8	3.7	5.4	3.9
FFO Leverage	3.8	3.6	5.4	3.9
FFO Net Leverage	3.8	3.6	5.4	3.9
Calculations for Forecast Publication				
Capex, Dividends, Acquisitions and Other Items Before FCF	-2,355	-2,602	-2,751	-2,776
FCF After Acquisitions and Divestitures	-931	-1,033	-1,565	-828

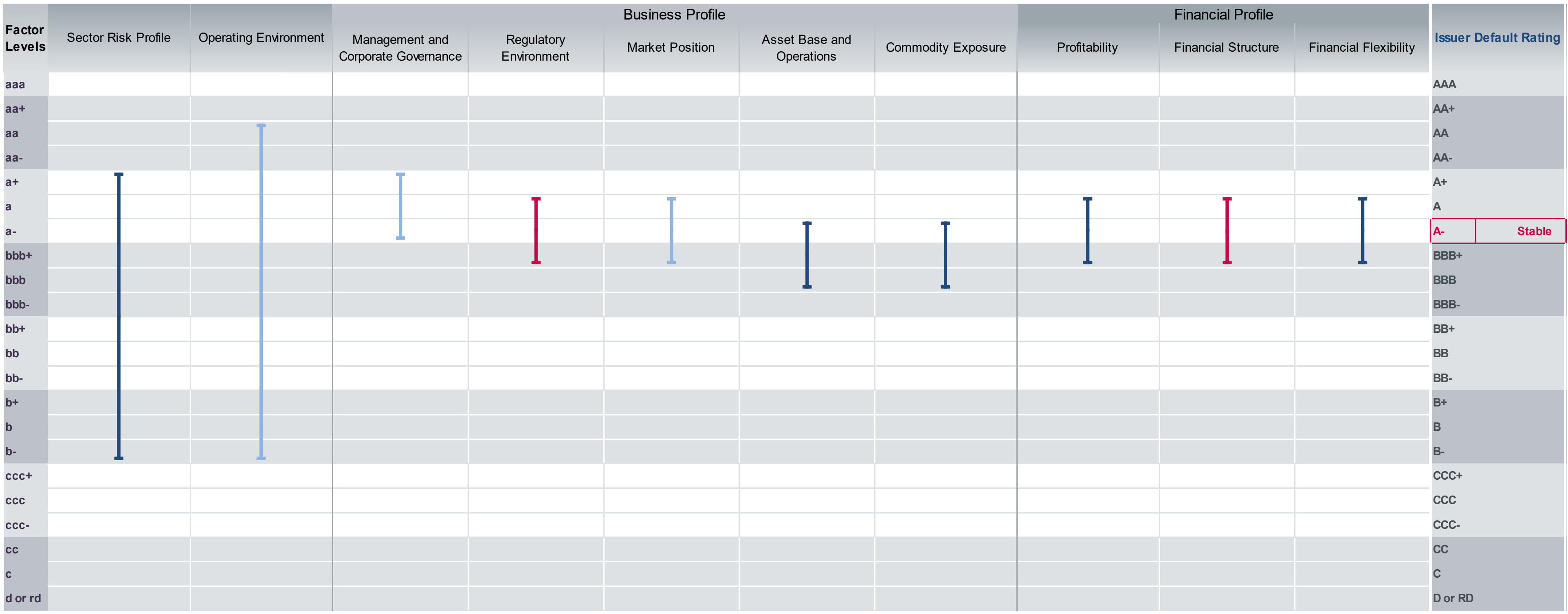
($ Mil., as of Dec. 31)	Historical			
	2018	2019	2020	2021
FCF Margin (After Net Acquisitions) (%)	-14.5	-16.3	-25.4	-11.9
Coverage Ratios (x)				
FFO Interest Coverage	6.3	7.2	5.1	7.8
FFO Fixed-Charge Coverage	6.1	6.5	5.1	7.8
EBITDAR Fixed-Charge Coverage	6.7	6.8	7.4	7.6
EBITDA Interest Coverage	6.9	7.5	7.4	7.6
Additional Metrics (%)				
CFO – Capex/Debt	-5.9	-7.2	-11.8	-1.2
CFO –Capex/Net Debt	-5.9	-7.2	-11.9	-1.2

CFO – Cash flow from operations.
Source: Fitch Ratings, Fitch Solutions

Ratings Navigator

FitchRatings **Consumers Energy Company** ESG Relevance:

Corporates Ratings Navigator
North American Utilities



Bar Chart Legend			
Vertical Bars = Range of Rating Factor		Bar Arrows = Rating Factor Outlook	
Bar Colors = Relative Importance		⇧	Positive
■	Higher Importance	⇩	Negative
■	Average Importance	⇳	Evolving
■	Lower Importance	□	Stable

FitchRatings

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Consumers Energy Company

Corporates Ratings Navigator
North American 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+			

Regulatory Environment

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 Position

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

a+	EBITDA Leverage	a	3.25x
a	FFO Leverage	a	3.5x
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 Interest Coverage	a	5.5x
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.

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.

FitchRatings

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Consumers Energy Company

Corporates Ratings Navigator
North American 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 right-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 some of the main 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 ratings criteria. The General Issues and Sector-Specific Issues draw on the classification standards published by the United Nations Principles for Responsible Investing (PRI) and the Sustainability Accounting Standards Board (SASB).

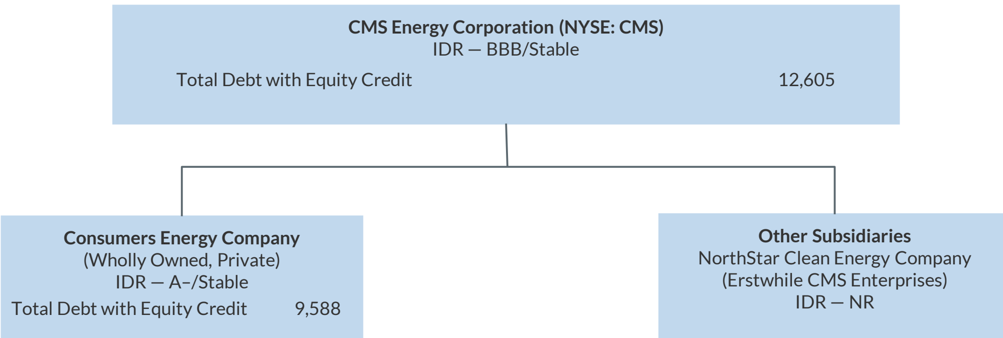
CREDIT-RELEVANT ESG SCALE

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.

Simplified Group Structure Diagram

Organizational and Debt Structure — Consumers Energy Company
($ Mil., as of Sept. 30, 2022)



IDR – Issuer Default Rating. NR – Not rated.
Source: Fitch Ratings, Fitch Solutions, Consumer Energy Company

FitchRatings

Peer Financial Summary

Company	Issuer Default Rating	Financial Statement Date	Gross Revenue ($ Mil.)	Funds Flow from Operations ($ Mil.)	FFO Interest Coverage (x)	FFO Leverage (x)	EBITDA Leverage (x)
Consumers Energy Company	A–						
	A–	2021	6,987	1,974	7.8	3.9	4.0
	A–	2020	6,155	1,239	5.1	5.4	3.8
	A–	2019	6,342	1,720	7.2	3.6	3.5
DTE Gas Company	BBB+						
	BBB+	2021	1,532	317	4.9	5.8	4.5
	BBB+	2020	1,396	337	5.3	5.1	4.4
	BBB+	2019	1,462	385	5.8	4.2	4.2
DTE Electric Company	A–						
	A–	2021	5,809	1,842	6.5	4.2	3.8
	A–	2020	5,506	1,849	6.7	3.9	3.6
	A–	2019	5,224	1,532	6.0	4.2	3.6
Northern States Power Company-Minnesota	A–						
	A–	2021	5,756	1,519	6.9	3.9	3.7
	A–	2020	5,101	1,415	6.9	3.7	3.5
	A–	2019	5,112	1,330	7.0	3.6	3.3
Northern States Power Company-Wisconsin	A–						
	A–	2021	1,105	254	7.4	3.7	3.4
	A–	2020	974	221	6.8	3.5	3.1
	A–	2019	981	220	6.9	3.4	3.3
Public Service Company of Colorado	A–						
	A–	2021	4,815	1,354	6.3	4.2	4.1
	A–	2020	4,183	1,169	6.6	4.4	4.1
	A–	2019	4,237	1,289	7.4	3.7	3.8
Wisconsin Electric Power Company	A						
	A	2020	3,657	818	2.8	2.5	2.4
	A	2019	3,367	783	2.7	2.5	2.4
	A	2018	3,497	779	2.6	2.3	2.5

Source: Fitch Ratings, Fitch Solutions

Fitch Adjusted Financials

($ Mil., as of Dec. 31, 2021)	Notes and Formulas	Reported Values	Sum of Adjustments	CORP- Lease Treatment	Other Adjustments	Adjusted Values
Income Statement Summary						
Revenue		7,021	-34		-34	6,987
EBITDAR		2,252	-57	-23	-34	2,195
EBITDAR After Associates and Minorities	(a)	2,252	-57	-23	-34	2,195
Lease Expense	(b)	0				0
EBITDA	(c)	2,252	-57	-23	-34	2,195
EBITDA After Associates and Minorities	(d) = (a-b)	2,252	-57	-23	-34	2,195
EBIT	(e)	1,175	-23	-16	-7	1,152
Debt and Cash Summary						
Other Off-Balance-Sheet Debt	(f)	0				0
Debt	(g)	8,971	-244	-46	-198	8,727
Lease-Equivalent Debt	(h)	0				0
Lease-Adjusted Debt	(i) = (g+h)	8,971	-244	-46	-198	8,727
Readily Available Cash and Equivalents	(j)	22				22
Not Readily Available Cash and Equivalents		22				22
Cash Flow Summary						
EBITDA After Associates and Minorities	(d) = (a-b)	2,252	-57	-23	-34	2,195
Preferred Dividends (Paid)	(k)	-2				-2
Interest Received	(l)	7				7
Interest (Paid)	(m)	-298	11	16	-5	-287
Cash Tax (Paid)		10				10
Other Items Before FFO		37	13		13	50
Funds from Operations (FFO)	(n)	2,008	-34	-7	-27	1,974
Change in Working Capital (Fitch-Defined)		-26				-26
Cash Flow from Operations (CFO)	(o)	1,982	-34	-7	-27	1,948
Non-Operating/Nonrecurring Cash Flow		0				0
Capital (Expenditures)	(p)	-2,052				-2,052
Common Dividends (Paid)		-724				-724
Free Cash Flow (FCF)		-794	-34	-7	-27	-828
Gross Leverage (x)						
EBITDAR Leverage[a]	(i/a)	4				4
FFO Adjusted Leverage	(i/(n-m-l-k+b))	4				4
FFO Leverage	(i-h)/(n-m-l-k)	4				4
EBITDA Leverage[a]	(i-h)/d	4				4
(CFO-Capex)/Debt (%)	(o+p)/(i-h)	-0.8				-1.2
Net Leverage (x)						
EBITDAR Leverage[a]	(i-j)/a	4.0				4.0
FFO Adjusted Net Leverage	(i-j)/(n-m-l-k+b)	3.9				3.9
FFO Net Leverage	(i-h-j)/(n-m-l-k)	3.9				3.9
EBITDA Net Leverage[a]	(i-h-j)/d	4.0				4.0
(CFO-Capex)/Debt (%)	(o+p)/(i-h-j)	-0.8				-1.2
Coverage (x)						
EBITDAR Fixed Charge Coverage[a]	a/(-m+b)	7.6				7.6
EBITDA Interest Coverage[a]	d/(-m)	7.6				7.6
FFO Fixed-Charge Coverage	(n-l-m-k+b)/(-m-k+b)	7.7				7.8
FFO Interest Coverage	(n-l-m-k)/(-m-k)	7.7				7.8

[a]EBITDA/R after dividends to associates and minorities. Note: Includes other off-balance-sheet debt.
Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

FitchRatings

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U21490-AG-CE-0128
Page **1** of **1**

Question:

3. Provide a copy of all rating agency reports covering Consumers Energy and CMS Energy for the most recent 24 months.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that information regarding CMS Energy is irrelevant to this matter as 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 attached.

Witness: MARC R. BLECKMAN
Date: March 1, 2024

THE REST OF THIS EXHIBIT CONSISTS OF 33 PAGES OF

THE S&P REPORT DATED AUGUST 17, 2023

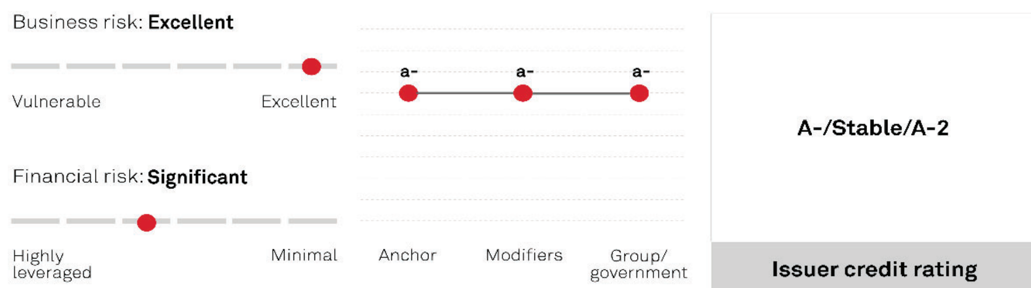
S&P Global Ratings

RatingsDirect®

Consumers Energy Co.

August 17, 2023

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Monopolistic vertically integrated electric utility and gas distribution utility operations.	Lack of operating diversity makes the company largely depend on Michigan regulators to sustain its credit quality.
Favorable regulatory construct in Michigan.	Exposure to environmental risks due to its dependence on natural gas and coal-fired generation (about 70% of electricity generated or purchased in 2022), though this is partially mitigated by a plan to retire coal by 2025.
Large customer base of 1.9 million electric and 1.8 million gas customers.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.
The company is an insulated subsidiary of its parent, CMS Energy, allowing us to rate it one notch above the parent.	Susceptibility to adverse weather events, including winter storms.
	Exposure to cyclical commercial and industrial customers, which account for about 47% of electric revenues and 20% of gas revenues.

We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk. We view Michigan's regulatory construct as above average compared to peers because of the benefit of a streamlined 10-month rate case process and various constructive rate mechanisms, such as the use of forward test-years, power supply and natural gas cost rider adjustments, and partial decoupling for the gas business. These mechanisms help the company earn its allowed ROE and minimize regulatory lag.

CE is currently in the middle of both an electric rate case and a gas rate case. The company filed for a $207.1 million electric rate increase based on a 10.25% return on equity (ROE) in May and reached a settlement with various intervenors for a $95 million gas rate increase based on a 9.90% ROE in July. We expect final rate orders by the end of 2023 and continue to monitor related developments.

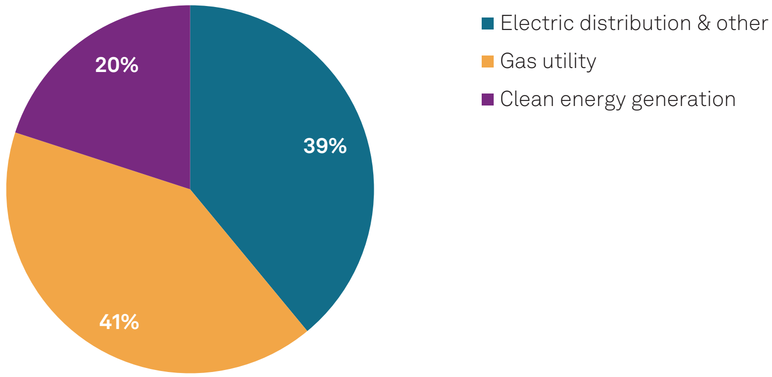
Consumers Energy Co. rate case details

	Present electric rate case: requested by company 5/1/2023	Previous electric rate case: authorized by Commission 1/19/2023	Present gas rate case: settlement filed 7/21/2023	Previous gas rate case: authorized by Commission 7/7/2022
Rate change amount ($ mil.)	207.1	155.0	95.0	170.0
Rate base ($ mil)	14,354.2	N/A	N/A	N/A
Rate base valuation method	Average	Average	Average	Average
Return on equity (%)	10.25	9.90	9.90	9.90
Common equity to total capital (%)	42.58	N/A	N/A	N/A
Rate of return (%)	6.11	N/A	N/A	N/A
Rate case test year end date	2/28/2025	12/31/2023	N/A	9/30/2023

Source: S&P CapitalIQ Pro. N/A—Not applicable.

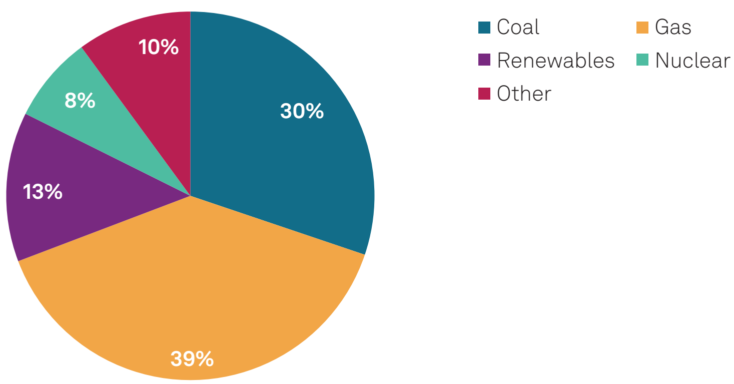
The company's elevated capital spending plan prioritizes infrastructure upgrades, and its energy transition plans. Over the next five years, CE plans to spend about $15.5 billion to maintain and upgrade its gas infrastructure and electric distribution systems and reduce its carbon emission. The capital plan includes investment of about $6.3 billion in the gas segment and about $9.2 billion in the electric segment. The company also intends to reduce its carbon exposure in line with its Integrated Resource Plan (IRP), which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 for CE’s electric division and a goal to retire CE’s owned coal-fired generation plants by 2025. Furthermore, the company's IRP targets a gradual reduction in its gas-fired generation dependance after 2025 as well as a target to meet 90% of its customer needs with clean energy sources by 2040. In addition, the company also announced a net-zero greenhouse gas emissions target for its gas distribution system by 2050.

Consumers Energy Co.'s investment plan



Source: Company fillings.

Consumers Energy Co.'s electricity generated and purchased by source



Source: Company filings.

The MPSC is currently investigating CE for malfunctioning meters and estimated billings. The company informed investors during its earnings call that meter vendors faced supply-chain issues since the start of the pandemic, which delayed the deployment of the company's updated meters moving to 5G from 3G. Given these delays, there were some issues with meter reads as more wireless carriers moved to 5G. This said, the company expects more consistent meter reads by the end of August. We continue to monitor the developments surrounding this investigation.

We expect CE's credit measures to remain within the significant financial risk profile category. Throughout our base-case scenario, we expect CE's funds from operations (FFO) to debt to be between 18%-20%.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of about 18%-20%.

Downside scenario

We could lower our rating on Consumers Energy if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or
- We could also lower our rating on Consumers Energy if we lower our rating on parent CMS Energy Corp.

Upside scenario

Although less likely, we could raise our rating on Consumer's Energy if we raise our rating on CMS Energy and Consumers Energy's stand-alone financial measures improve, reflecting FFO to debt 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 about $3 billion annually;
- Annual dividends averaging about $960 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

Consumers Energy Inc.—Forecast summary

Period ending	2021a	2022a	2023e	2024f	2025f	2026f	2027f
(Mil. $)							
Revenue	6,987	8,117	7,932	8,376	8,896	9,428	9,985
EBITDA (reported)	2,252	2,321	2,653	2,902	3,143	3,392	3,655
Plus: Operating lease adjustment (OLA) rent	8	6	6	6	6	6	6
Plus/(less): Other	146	70	51	(47)	(58)	(58)	(65)
EBITDA	2,406	2,397	2,710	2,861	3,092	3,340	3,595
Less: Cash interest paid	(375)	(342)	(406)	(478)	(533)	(573)	(605)
Less: Cash taxes paid	10	2	--	(102)	(41)	(92)	(66)

Consumers Energy Inc.—Forecast summary

Funds from operations (FFO)	2,041	2,058	2,303	2,281	2,518	2,675	2,925
Cash flow from operations (CFO)	2,014	985	2,717	2,221	2,471	2,585	2,798
Capital expenditure (capex)	2,136	2,275	3,707	2,823	3,117	2,765	2,737
Free operating cash flow (FOCF)	(123)	(1,290)	(990)	(602)	(647)	(180)	61
Dividends	724	771	788	913	968	1,044	1,099
Discretionary cash flow (DCF)	(847)	(2,061)	(1,778)	(1,515)	(1,615)	(1,224)	(1,038)
Debt (reported)	8,810	10,287	11,585	12,402	13,217	13,838	14,354
Plus: Lease liabilities debt	74	81	89	99	110	124	140
Plus: Pension and other postretirement debt	--	--	--	--	--	--	--
Less: Accessible cash and liquid Investments	(22)	(43)	(43)	(43)	(43)	(43)	(43)
Plus/(less): Other	535	680	27	98	180	267	355
Debt	9,397	11,005	11,658	12,556	13,465	14,186	14,807
Equity	9,279	10,155	10,885	11,687	12,603	13,369	14,096
Cash and short-term investments (reported)	22	43	43	43	43	43	43
Adjusted ratios							
Debt/EBITDA (x)	3.9	4.6	4.3	4.4	4.4	4.2	4.1
FFO/debt (%)	21.7	18.7	19.8	18.2	18.7	18.9	19.8
FFO cash interest coverage (x)	6.4	7.0	6.7	5.8	5.7	5.7	5.8
EBITDA interest coverage (x)	6.3	6.4	6.2	5.7	5.5	5.6	5.7
CFO/debt (%)	21.4	8.9	23.3	17.7	18.3	18.2	18.9
FOCF/debt (%)	(1.3)	(11.7)	(8.5)	(4.8)	(4.8)	(1.3)	0.4
DCF/debt (%)	(9.0)	(18.7)	(15.3)	(12.1)	(12.0)	(8.6)	(7.0)
Debt/debt and equity (%)	50.3	52.0	51.7	51.8	51.7	51.5	51.2

All figures adjusted by S&P Global Ratings. a—Actual. e—Estimate. f—Forecast.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE'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. CE contributes to about 95% of CMS' EBITDA.

Peer Comparison

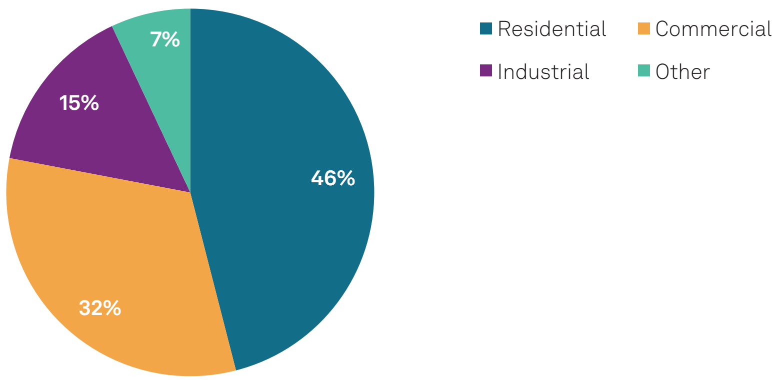
Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Wisconsin Power & Light Co.	Wisconsin Electric Power Co.	Consolidated Edison Co. of New York Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31	2022-12-31	2022-12-31
Mil.	$	$	$	$	$
Revenue	8,117	6,353	1,856	4,070	13,268
EBITDA	2,397	2,715	742	1,614	4,048
Funds from operations (FFO)	2,058	2,389	562	986	3,140
Interest	374	551	123	230	890
Cash interest paid	342	359	124	540	821
Operating cash flow (OCF)	985	1,654	286	726	3,264
Capital expenditure	2,275	2,617	1,007	1,018	3,563
Free operating cash flow (FOCF)	(1,290)	(964)	(721)	(293)	(299)
Discretionary cash flow (DCF)	(2,061)	(1,727)	(926)	(922)	(1,277)
Cash and short-term investments	43	15	5	6	1,056
Gross available cash	43	15	5	6	1,056
Debt	11,005	11,528	3,406	5,843	21,344
Equity	10,155	9,695	3,491	4,152	16,878
EBITDA margin (%)	29.5	42.7	40.0	39.7	30.5
Return on capital (%)	6.3	7.6	8.1	11.8	5.8
EBITDA interest coverage (x)	6.4	4.9	6.0	7.0	4.5
FFO cash interest coverage (x)	7.0	7.6	5.5	2.8	4.8
Debt/EBITDA (x)	4.6	4.2	4.6	3.6	5.3
FFO/debt (%)	18.7	20.7	16.5	16.9	14.7
OCF/debt (%)	8.9	14.3	8.4	12.4	15.3
FOCF/debt (%)	(11.7)	(8.4)	(21.2)	(5.0)	(1.4)
DCF/debt (%)	(18.7)	(15.0)	(27.2)	(15.8)	(6.0)

Business Risk

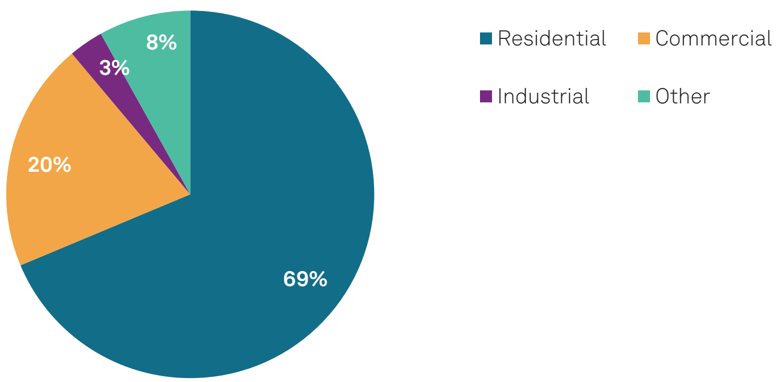
Our assessment of CE's business risk profile reflects the company's monopolistic electric and natural gas utility operations and effective management of regulatory risk. The Michigan Public Service Commission (MPSC) regulates CE and we view the regulatory environment in Michigan as above average compared to peers. This is demonstrated through the company's use of forward-looking test years and a streamlined 10-month rate case process. Furthermore, CE benefits from 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 nonfuel revenues with the revenues approved by the MPSC. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag. The company also actively manages its gas supply for its gas system as it injects natural gas into storage during the summer months for use during the winter months. During 2022, 48 percent of the natural gas supplied to all customers during the winter months was supplied from storage. Furthermore, CE's business risk profile is bolstered by the company's large customer base of about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan. This said, the company is exposed to cyclical commercial and industrial customers for its electric operations which contribute about 47% of the company's electric revenues.

Consumers Energy Co.'s electrical revenue by customer class



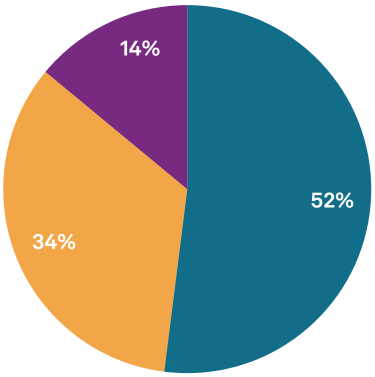
Source: Company filings.

Consumers Energy Co.'s gas revenue by customer class



Source: Company filings.

Consumers Energy Co.'s gas supply sources



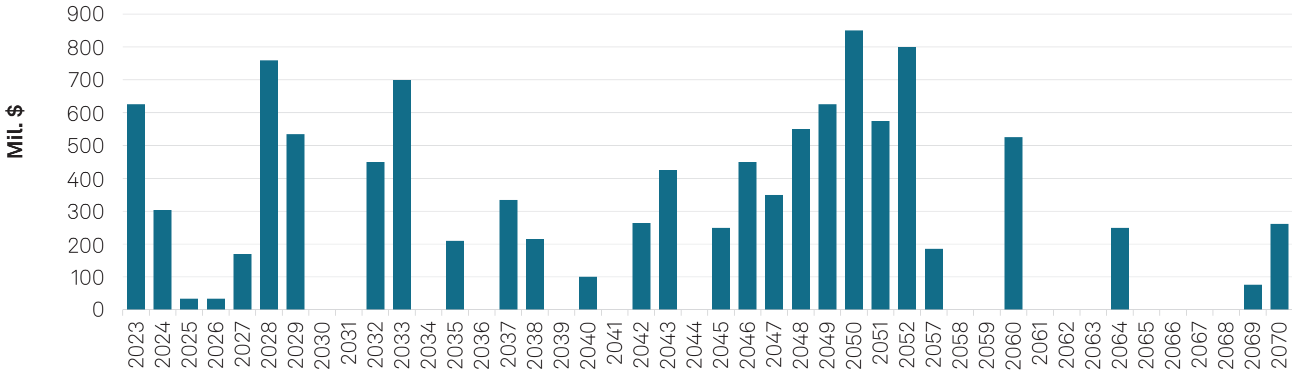
Source: Company filings.

Financial Risk

We assess CE'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 around $3 billion annually over the forecast period (inclusive of the company's acquisition of the Covert gas plant), dividends averaging about $960 million annually, equity injections by the parent to maintain the company's capital structure, securitization issuance related to the retirement costs of the company's Karn coal plant units 1 and 2, continued use of existing regulatory mechanisms, negative discretionary cash flow, and refinancing of all debt maturities. As such, we anticipate financial measures to be consistent with the middle of the range for the significant financial risk category. Specifically, we forecast FFO to debt between 18%-20%.

Debt maturities

Debt Maturities
As of June 2023



Source. Company filings

Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022
Reporting period	2017a	2018a	2019a	2020a	2021a	2022a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,187	6,430	6,341	6,155	6,987	8,117
EBITDA	2,267	2,152	2,252	2,392	2,406	2,397
Funds from operations (FFO)	1,954	1,665	1,823	1,968	2,041	2,058
Interest expense	347	355	335	393	380	374
Cash interest paid	314	331	296	373	375	342
Operating cash flow (OCF)	1,792	1,533	1,688	1,265	2,014	985
Capital expenditure	1,721	1,920	2,191	2,254	2,136	2,275
Free operating cash flow (FOCF)	71	(387)	(502)	(989)	(123)	(1,290)
Discretionary cash flow (DCF)	(453)	(918)	(1,094)	(1,628)	(847)	(2,061)
Cash and short-term investments	44	39	11	20	22	43
Gross available cash	44	39	11	20	22	43
Debt	7,037	7,774	8,238	9,113	9,397	11,005
Common equity	6,488	6,920	7,737	8,556	9,279	10,155
Adjusted ratios						
EBITDA margin (%)	36.6	33.5	35.5	38.9	34.4	29.5
Return on capital (%)	9.8	7.9	7.7	7.5	6.9	6.3
EBITDA interest coverage (x)	6.5	6.1	6.7	6.1	6.3	6.4
FFO cash interest coverage (x)	7.2	6.0	7.2	6.3	6.4	7.0
Debt/EBITDA (x)	3.1	3.6	3.7	3.8	3.9	4.6
FFO/debt (%)	27.8	21.4	22.1	21.6	21.7	18.7
OCF/debt (%)	25.5	19.7	20.5	13.9	21.4	8.9

Consumers Energy Co.--Financial Summary

FOCF/debt (%)	1.0	(5.0)	(6.1)	(10.9)	(1.3)	(11.7)
DCF/debt (%)	(6.4)	(11.8)	(13.3)	(17.9)	(9.0)	(18.7)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2022									
Company reported amounts	10,287	10,155	8,151	2,321	1,233	335	2,397	994	771	2,239
Cash taxes paid	-	-	-	-	-	-	2	-	-	-
Cash interest paid	-	-	-	-	-	-	(331)	-	-	-
Lease liabilities	81	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	6	1	1	(1)	5	-	-
Accessible cash and liquid investments	(43)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	2	(2)	(2)	-	(2)
Share-based compensation expense	-	-	-	25	-	-	-	-	-	-
Securitized stranded costs	(170)	-	(34)	(34)	(6)	(6)	6	(28)	-	-
Power purchase agreements	356	-	-	51	14	14	(14)	38	-	38
Asset-retirement obligations	589	-	-	28	28	28	-	-	-	-
Nonoperating income (expense)	-	-	-	-	(8)	-	-	-	-	-
Reclassification of interest and dividend cash flows	-	-	-	-	-	-	-	(22)	-	-
Debt: other	(95)	-	-	-	-	-	-	-	-	-
Total adjustments	718	-	(34)	76	29	39	(340)	(9)	-	36
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	11,005	10,155	8,117	2,397	1,262	374	2,058	985	771	2,275

Liquidity

We assess CE's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecasted consolidated EBITDA declines by 10%. We believe the supportive regulatory framework provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, CE has the ability to absorb high-impact, low-probability events, in our view, as the company maintains about $1.1 billion in committed credit facilities through 2027, maintains another $250 million in committed credit facilities through

November 2024, and can likely lower its capital spending (averaging about $3 billion annually) during stressful periods, indicative of a limited need for refinancing under such conditions. CE can borrow $500 million from the parent CMS Energy as per its renewed credit agreement in December 2022. Furthermore, our assessment reflects the company's prudent risk management and sound relationships with its banking group. Overall, we believe that the company should be able to withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has around $300 million of long-term debt maturities coming up in 2024 and we expect the company to proactively address these maturities well in advance of their scheduled due dates.

Principal liquidity sources

- Cash FFO of about $2.3 billion;
- Credit facilities of about $1.3 billion;
- Working capital inflows of about $150 million; and
- Available cash of about $100 million.

Principal liquidity uses

- Debt maturities of about $700 million over the next 12 months;
- Estimated maintenance capital spending of about $1.9 billion; and
- Dividends of about $850 million.

Environmental, Social, And Governance

Environmental factors are a moderately negative consideration in our credit rating analysis of CE. The company's use of above-average fossil fuel generation sources exposes it to heightened climate transition risk. The utility's generation capacity portfolio consists of 24% natural gas, 33% coal, 22% renewables, and 21% oil/gas as of Dec. 31, 2022. Slightly mitigating this risk is the utility's accelerated coal retirement plan, which includes a goal to be coal-free by 2025 and have 90% of its capacity portfolio sourced from clean energy resources by 2040.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy because we view the utility as integral to the group's identity, highly unlikely to be sold 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 CE 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 are:

- CE 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.
- CE 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.
- CE 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 CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE 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 CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

CE's capital structure consists of about $10.9 billion of long-term debt, including about $10.8 billion in first-mortgage bonds (FMBs) and about $110 million of tax-exempt revenue bonds.

Analytical conclusions

We rate the company's senior unsecured debt 'A-', in-line with the long-term issuer credit rating on CE as the rated issuances are senior unsecured debt issued by a qualifying investment grade utility as per our criteria.

We base our 'A-2' short-term rating on CE on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- 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 that qualify for a recovery rating as defined in our criteria.
- CE'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.

Rating Component Scores

Foreign currency issuer credit rating	A-/Stable/A-2
Local currency 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-
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)

Rating Component Scores

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 on SACP)

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- 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
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, 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: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of August 17, 2023)*

Consumers Energy Co.

Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2

Ratings Detail (as of August 17, 2023)*

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-
Preferred Stock	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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Tear Sheet:

CMS Energy Corp.'s Recent Stranded Cost Securitization Is Consistent With Our Expectations

December 15, 2023

On Dec. 12, 2023, CMS Energy Corp. announced that Consumers 2023 Securitization Funding LLC issued $646 million of securitization bonds. The securitization issuance was consistent with our base case and finalizes CMS' previously announced plans to securitize and recover the costs related to the retirement of its Karn coal plant units 1 & 2. We view this securitization as supportive of credit quality, allowing the utility to fully recover its costs associated with these coal plants. For our financial analysis of CMS, we deconsolidate securitization debt (and associated revenues and expenses), primarily reflecting the irrevocable non-bypassable charge on CMS' customer bills and the first-priority security interest in the transition property.

Under our base case, we continue to assume CMS' funds from operations (FFO) to debt will remain consistently between 13% and 15%. Under our base-case scenario, we expect elevated capital spending averaging $3.0 billion-$3.5 billion annually over the forecast period and dividends averaging $700 million-$750 million annually. We also forecast limited growth of NorthStar as a proportion of the overall company, continued use of existing regulatory mechanisms, continued negative discretionary cash flow that we expect it will fund will in a balanced manner, and the refinancing of all debt maturities.

We assess CMS' 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. As such, we expect the company's financial measures will consistently reflect the lower end of the range for its significant financial risk profile category.

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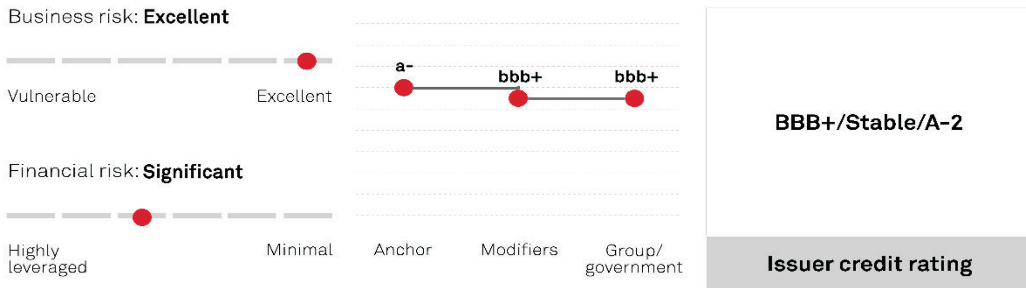
Ratings Score Snapshot



Company Description

CMS is a vertically integrated regulated utility holding company that derives about 95% of its EBITDA from its regulated utility operations at subsidiary Consumers Energy Co. (CE). The remainder comes from its nonregulated electric generation business NorthStar Clean Energy (previously CMS Enterprises). CE operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE'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. NorthStar is an independent power producer and marketer that contracts much of its generation assets in its portfolio to high-credit-quality counterparties and sells electricity on a merchant basis.

Outlook

The stable outlook on CMS reflects our expectation that it will continue focusing on its core utility operations and reach constructive regulatory outcomes to avoid increasing its business risk. The outlook also reflects our base-case forecast for consolidated FFO to debt of 13%-15% over the forecast period, which is on the lower end of the range for the significant financial risk profile category.

Downside scenario

We could lower our rating on CMS over the next 24 months if:

- Its business risk profile weakens because of reduced regulatory support or a material increase in its nonutility operations; and
- Its financial measures consistently underperform our base-case forecast and decline such that its FFO to debt remains consistently below 13%.

This could occur if the company's rate case outcomes are consistently weaker than expected, it faces greater regulatory lag, or it increases its primarily debt-financed capital spending.

Upside scenario

We could raise the rating on CMS over the next 24 months if:

- Its business risk profile remains robust; and
- Its financial measures strengthen such that they consistently exceed our base-case assumptions, including FFO to total debt of more than 16%.

We believe the company could improve its financial measures through deleveraging, greater equity funding of its capital investments, and continuous cash flow support from its rate case activity.

Key Metrics

CMS Energy Corp.--Forecast summary

Period ending	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. $)	2021a	2022a	2023e	2024f	2025fe	2026f	2027f
Revenue	7,295	8,562	8,069	8,705	9,207	9,804	10,387
EBITDA (reported)	2,260	2,350	2,525	2,896	3,129	3,410	3,678
Plus: Operating lease adjustment (OLA) rent	8	6	6	6	6	6	6
Plus/(less): Other	144	72	86	(17)	(50)	(51)	(54)
EBITDA	2,412	2,428	2,617	2,885	3,086	3,365	3,630
Less: Cash interest paid	(546)	(509)	(531)	(589)	(678)	(747)	(811)
Less: Cash taxes paid	(16)	(1)	(47)	(62)	--	(45)	(32)
Funds from operations (FFO)	1,850	1,917	2,039	2,234	2,407	2,573	2,787
Cash flow from operations (CFO)	1,871	859	2,596	2,177	2,386	2,448	2,673
Capital expenditure (capex)	2,160	2,410	3,876	3,077	3,620	3,226	3,138
Free operating cash flow (FOCF)	(290)	(1,550)	(1,279)	(899)	(1,233)	(778)	(464)
Dividends	551	598	652	720	773	823	878
Discretionary cash flow (DCF)	(840)	(2,148)	(1,932)	(1,619)	(2,006)	(1,601)	(1,342)
Debt (reported)	12,422	14,232	15,728	17,010	18,114	18,905	19,469
Plus: Lease liabilities debt	78	108	151	213	303	433	623
Plus: Pension and other postretirement debt	--	--	--	--	--	--	--
Less: Accessible cash and liquid Investments	(452)	(164)	(164)	(164)	(164)	(164)	(164)
Plus/(less): Other	(60)	(250)	(905)	(920)	(867)	(781)	(690)
Debt	11,988	13,926	14,810	16,139	17,385	18,393	19,238
Equity	8,193	8,600	9,046	9,598	10,310	11,036	11,732
Cash and short-term investments (reported)	452	164	164	164	164	164	164
Adjusted ratios							
Debt/EBITDA (x)	5.0	5.7	5.7	5.6	5.6	5.5	5.3
FFO/debt (%)	15.4	13.8	13.8	13.8	13.8	14.0	14.5
FFO cash interest coverage (x)	4.4	4.8	4.8	4.8	4.5	4.4	4.4
EBITDA interest coverage (x)	4.6	4.8	4.7	4.7	4.4	4.4	4.4
CFO/debt (%)	15.6	6.2	17.5	13.5	13.7	13.3	13.9
FOCF/debt (%)	(2.4)	(11.1)	(8.6)	(5.6)	(7.1)	(4.2)	(2.4)
DCF/debt (%)	(7.0)	(15.4)	(13.0)	(10.0)	(11.5)	(8.7)	(7.0)
Debt/debt and equity (%)	59.4	61.8	62.1	62.7	62.8	62.5	62.1

All figures are adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. $--U.S. dollar.

Financial Summary

CMS Energy Corp.--Financial Summary

Period ending	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022
Reporting period	2017a	2018a	2019a	2020a	2021a	2022a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,548	6,839	6,810	6,646	7,295	8,562
EBITDA	2,361	2,263	2,381	2,561	2,412	2,428
Funds from operations (FFO)	1,890	1,891	1,954	1,951	1,850	1,917
Interest expense	509	517	527	594	528	506
Cash interest paid	466	495	485	668	546	509
Operating cash flow (OCF)	1,782	1,795	1,910	1,273	1,871	859
Capital expenditure	1,754	2,172	2,210	2,401	2,160	2,410
Free operating cash flow (FOCF)	28	(377)	(300)	(1,128)	(290)	(1,550)
Discretionary cash flow (DCF)	(347)	(790)	(767)	(1,637)	(840)	(2,148)
Cash and short-term investments	182	153	140	168	452	164
Gross available cash	182	153	140	168	452	164
Debt	11,196	12,214	13,364	14,998	11,988	13,926
Common equity	4,478	5,032	5,610	7,082	8,193	8,600
Adjusted ratios						
EBITDA margin (%)	36.1	33.1	35.0	38.5	33.1	28.4
Return on capital (%)	9.1	8.0	7.1	6.9	5.8	5.9
EBITDA interest coverage (x)	4.6	4.4	4.5	4.3	4.6	4.8
FFO cash interest coverage (x)	5.1	4.8	5.0	3.9	4.4	4.8
Debt/EBITDA (x)	4.7	5.4	5.6	5.9	5.0	5.7
FFO/debt (%)	16.9	15.5	14.6	13.0	15.4	13.8
OCF/debt (%)	15.9	14.7	14.3	8.5	15.6	6.2
FOCF/debt (%)	0.2	(3.1)	(2.2)	(7.5)	(2.4)	(11.1)
DCF/debt (%)	(3.1)	(6.5)	(5.7)	(10.9)	(7.0)	(15.4)

Peer Comparison

CMS Energy Corp.--Peer Comparisons

	CMS Energy Corp.	DTE Energy Co.	Alliant Energy Corp.	Ameren Corp.	WEC Energy Group Inc.
Foreign currency issuer credit rating	BBB+/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	BBB+/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31	2022-12-31	2022-12-31
Mil.	$	$	$	$	$

CMS Energy Corp.--Peer Comparisons

Revenue	8,562	19,184	4,205	7,957	9,597
EBITDA	2,428	3,481	1,620	3,009	3,299
Funds from operations (FFO)	1,917	2,855	1,286	2,495	2,732
Interest	506	850	334	547	562
Cash interest paid	509	629	328	523	515
Operating cash flow (OCF)	859	1,965	469	2,204	2,112
Capital expenditure	2,410	3,367	1,468	3,354	2,345
Free operating cash flow (FOCF)	(1,550)	(1,402)	(999)	(1,151)	(233)
Discretionary cash flow (DCF)	(2,148)	(2,171)	(1,456)	(1,779)	(1,237)
Cash and short-term investments	164	33	20	250	29
Gross available cash	164	33	20	490	29
Debt	13,926	19,924	9,139	14,543	17,737
Equity	8,600	10,856	6,276	10,573	11,851
EBITDA margin (%)	28.4	18.1	38.5	37.8	34.4
Return on capital (%)	5.9	6.7	7.1	6.6	7.7
EBITDA interest coverage (x)	4.8	4.1	4.9	5.5	5.9
FFO cash interest coverage (x)	4.8	5.5	4.9	5.8	6.3
Debt/EBITDA (x)	5.7	5.7	5.6	4.8	5.4
FFO/debt (%)	13.8	14.3	14.1	17.2	15.4
OCF/debt (%)	6.2	9.9	5.1	15.2	11.9
FOCF/debt (%)	(11.1)	(7.0)	(10.9)	(7.9)	(1.3)
DCF/debt (%)	(15.4)	(10.9)	(15.9)	(12.2)	(7.0)

Environmental, Social, And Governance

Environmental factors are a moderately negative consideration in our credit rating analysis of CMS. The company's use of above-average fossil fuel generation sources exposes it to heightened climate transition risks. The company's generation capacity portfolio comprises 31% natural gas, 26% coal, 25% renewables, 16% oil and gas, and 2% wood waste as of Dec. 31, 2022. Slightly mitigating this risk is the company's accelerated coal retirement plan for its utility, which includes a goal to be coal-free by 2025 and have 90% of its capacity portfolio sourced from clean energy resources by 2040.

Rating Component Scores

Foreign currency issuer credit rating	BBB+/Stable/A-2
Local currency issuer credit rating	BBB+/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-
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	Negative (-1 notch)
Stand-alone credit profile	bbb+

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- 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 | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, 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: Principles Of Credit Ratings, Feb. 16, 2011

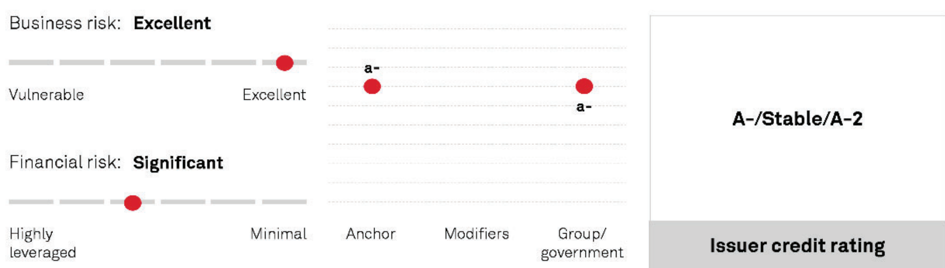
S&P Global
Ratings

RatingsDirect®

Consumers Energy Co.

July 25, 2022

Ratings Score Snapshot



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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, partially mitigated by a plan to exit coal by 2025.
Sufficient insulating measures for higher rating than group credit profile.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.

The Michigan Public Service Commission (MPSC) recently approved Consumers Energy Co.'s (CE's) gas rate case settlement agreement. The settlement approves a $170 million revenue increase, premised on a 9.9% return on equity (ROE), and it goes into effect on Oct. 1, 2022. CE had initially filed for a $278.4 million revenue increase in December 2021 based on an ROE of 10.5%, which the company later revised to $233 million based on a ROE of 10.25%. This approval includes the revenue decoupling mechanism that was approved in previous rate cases. However, this outcome was slightly offset by the agreement to write off capital expenditures, net of insurance proceeds tied to the repairs associated with the 2019 Ray compressor station fire.

Following a less-than-favorable outcome in its most recent electric rate case, CE filed another rate case increase request with the MPSC for its electric division in April 2022. The company is seeking a $266.4 million rate increase based on a 10.25% ROE. The outcome of this rate case is pending, and we continue to monitor related developments.

CE plans to exit coal by 2025. The company's integrated resource plan (IRP) targets to exit coal by 2025 and substantially reduce dependence on generation from natural gas.

The company's elevated capital spending plan prioritizes infrastructure upgrades and energy transition plans. Over the next five years, CE plans to spend about $14.3 billion to maintain and upgrade its gas infrastructure and electric distribution systems and reduce its carbon emission. The capital plan includes investment of about $6 billion in the gas segment and about $8 billion in the electric segment.

As of 31 March 2022, CE's capacity portfolio consisted of 26% natural gas,18% coal and 11% oil/gas. The company intends to reduce its carbon exposure in line with its IRP, which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 for the electric division and eliminate coal-sourced electric generation by 2025.

We expect CE will continue to effectively manage regulatory risk, in line with the company's business risk profile. We view Michigan's regulatory construct as above average compared to peers because of the benefit of a streamlined 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.

We expect CE's credit measures to remain in the middle of the range for its financial risk profile category. We expect funds from operations (FFO) to debt of about 19%-21% over the next three years.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of about 20%.

Downside scenario

We could lower our rating on Consumers Energy if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or
- We could also lower our rating on Consumers Energy if we lower our rating on parent CMS Energy Corp.

Upside scenario

Although less likely, we could raise our rating on Consumer's Energy if we raise our rating on CMS Energy and Consumer's Energy's stand-alone financial measures improve, reflecting FFO to debt 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 about $2.4 billion annually;
- Annual dividends averaging about $800 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

Consumers Energy Co.--Key Metrics

Mil. $	2021a	2022e	2023f
FFO to debt (%)	21.7	19-20	19-20
Debt to EBITDA (x)	3.9	4-5	4-5
FFO interest coverage (x)	6.4	6-7	6-7

a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE'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

Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Alliant Energy Corp.	Ameren Corp.	WEC Energy Group Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2021-12-31	2021-12-31	2021-12-31	2021-12-31	2021-12-31
Mil.	$	$	$	$	$
Revenue	6,987	5,809	3,669	6,394	8,316
EBITDA	2,406	2,596	1,473	2,663	3,033
Funds from operations (FFO)	2,041	2,256	1,190	2,201	2,490
Interest	380	504	285	434	530
Cash interest paid	375	335	280	464	510
Operating cash flow (OCF)	2,014	1,273	574	1,611	2,071
Capital expenditure	2,136	3,008	1,162	3,506	2,284
Free operating cash flow (FOCF)	(123)	(1,735)	(588)	(1,896)	(213)
Discretionary cash flow (DCF)	(847)	(2,323)	(1,191)	(2,493)	(1,106)
Cash and short-term investments	22	9	39	8	16
Gross available cash	22	9	39	256	16

Consumers Energy Co.--Peer Comparisons

Debt	9,397	10,115	8,292	13,325	16,339
Equity	9,279	8,903	5,990	9,765	11,348
EBITDA margin (%)	34.4	44.7	40.1	41.6	36.5
Return on capital (%)	6.9	8.0	6.3	6.6	7.4
EBITDA interest coverage (x)	6.3	5.1	5.2	6.1	5.7
FFO cash interest coverage (x)	6.4	7.7	5.3	5.7	5.9
Debt/EBITDA (x)	3.9	3.9	5.6	5.0	5.4
FFO/debt (%)	21.7	22.3	14.4	16.5	15.2
OCF/debt (%)	21.4	12.6	6.9	12.1	12.7
FOCF/debt (%)	(1.3)	(17.2)	(7.1)	(14.2)	(1.3)
DCF/debt (%)	(9.0)	(23.0)	(14.4)	(18.7)	(6.8)

Business Risk

Our assessment of CE's business risk profile reflects the company's lower-risk electric and natural gas utility operations. CE is a larger-than-average utility that serves about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan. About 80% of the company's electric customer revenue base is residential and commercial, providing stable cash flow and mitigating CE's exposure to industrial cyclicality. CE is a wholly owned subsidiary of CMS Energy and contributes about 95% of CMS Energy's consolidated operations.

The MPSC regulates CE. 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 streamlined 10-month rate case process. CE 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 nonfuel revenues with the revenues approved by the MPSC. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag.

Financial Risk

We assess CE'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 around $2.8 billion annually over the forecast period. 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.

Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2016	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021
Reporting period	2016a	2017a	2018a	2019a	2020a	2021a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,030	6,187	6,430	6,341	6,155	6,987
EBITDA	2,168	2,267	2,152	2,252	2,392	2,406
Funds from operations (FFO)	1,820	1,954	1,665	1,823	1,968	2,041
Interest expense	333	347	355	335	393	380

Consumers Energy Co.--Financial Summary

Cash interest paid	298	314	331	296	373	375
Operating cash flow (OCF)	1,768	1,792	1,533	1,688	1,265	2,014
Capital expenditure	1,754	1,721	1,920	2,191	2,254	2,136
Free operating cash flow (FOCF)	15	71	(387)	(502)	(989)	(123)
Discretionary cash flow (DCF)	(486)	(453)	(918)	(1,094)	(1,628)	(847)
Cash and short-term investments	131	44	39	11	20	22
Gross available cash	131	44	39	11	20	22
Debt	6,734	7,037	7,774	8,238	9,113	9,397
Common equity	5,939	6,488	6,920	7,737	8,556	9,279
Adjusted ratios						
EBITDA margin (%)	36.0	36.6	33.5	35.5	38.9	34.4
Return on capital (%)	9.7	9.8	7.9	7.7	7.5	6.9
EBITDA interest coverage (x)	6.5	6.5	6.1	6.7	6.1	6.3
FFO cash interest coverage (x)	7.1	7.2	6.0	7.2	6.3	6.4
Debt/EBITDA (x)	3.1	3.1	3.6	3.7	3.8	3.9
FFO/debt (%)	27.0	27.8	21.4	22.1	21.6	21.7
OCF/debt (%)	26.3	25.5	19.7	20.5	13.9	21.4
FOCF/debt (%)	0.2	1.0	(5.0)	(6.1)	(10.9)	(1.3)
DCF/debt (%)	(7.2)	(6.4)	(11.8)	(13.3)	(17.9)	(9.0)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2021									
Company reported amounts	8,810	9,279	7,021	2,252	1,175	311	2,406	1,982	724	2,052
Cash taxes paid	-	-	-	-	-	-	10	-	-	-
Cash interest paid	-	-	-	-	-	-	(330)	-	-	-
Lease liabilities	74	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	8	2	2	(2)	6	-	-
Accessible cash and liquid investments	(22)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	3	(3)	(3)	-	(3)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Share-based compensation expense	-	-	-	21	-	-	-	-	-	-
Securitized stranded costs	(198)	-	(34)	(34)	(7)	(7)	7	(27)	-	-
Power purchase agreements	647	-	-	135	47	47	(47)	87	-	87
Asset-retirement obligations	478	-	-	24	24	24	-	-	-	-
Nonoperating income (expense)	-	-	-	-	5	-	-	-	-	-
Reclassification of interest and dividend cash flows	-	-	-	-	-	-	-	(32)	-	-
Debt: other	(392)	-	-	-	-	-	-	-	-	-
Total adjustments	587	-	(34)	154	71	69	(365)	32	-	84
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	9,397	9,279	6,987	2,406	1,246	380	2,041	2,014	724	2,136

Liquidity

As of March 31, 2022, we assessed CE's liquidity as adequate to cover its needs over the following 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 CE's sound relationships with banks, satisfactory standing in the credit markets, and generally prudent risk management.

Principal liquidity sources

- Cash FFO of about $2 billion;
- Credit facilities of about $1.1 billion; and
- Available cash of about $12 million as of March 31, 2022.

Principal liquidity uses

- Debt maturities of about $365 million as of Mar. 31, 2022;
- Estimated capital spending of about $2.3 billion; and
- Dividends of about $760 million.

Environmental, Social, And Governance

ESG Credit Indicators

E-1	E-2	E-3	E-4	E-5	S-1	S-2	S-3	S-4	S-5	G-1	G-2	G-3	G-4	G-5

Environmental	Social	Governance
- Climate transition risks	- N/A	- N/A

N/A--Not applicable. ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1 - 5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicator Definitions And Applications," published Oct. 13, 2021.

Environmental factors are a moderately negative consideration in our credit rating analysis of CE. The company's use of above-average fossil fuel generation sources exposes it to heightened climate transition risk. The utility's generation capacity portfolio consists of 26% natural gas, 18% coal, 14% renewables, 11% oil/gas, and 8% nuclear as of March 31, 2022. Slightly mitigating this risk is the utility's accelerated coal retirement plan, which includes a goal to be coal-free by 2025 and have 60% of its capacity portfolio sourced from renewables by 2040.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy because we view the utility as integral to the group's identity, highly unlikely to be sold 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 CE 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 are:

- CE 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.
- CE 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.
- CE 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 CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE 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 CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

As of Dec. 31, 2021, CE'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 CE on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- 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 that qualify for a recovery rating as defined in our criteria.
- CE'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.

Rating Component Scores

Foreign currency issuer credit rating	A-/Stable/A-2
Local currency 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-
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: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- 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
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- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of July 25, 2022)*

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-
Preferred Stock	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.

U21490-AG-CE-0132
Page **1** of **1**

Question:

7. Refer to page 15 of Mr. Bleckman's direct testimony in lines 5 to 14, where he states that an equity ratio below 51.5% and an ROE below 10.25% could cause the Company's "...FFO to Debt ratio to drop below established rating agency thresholds placing the Company's credit quality and credit ratings at risk..." Please:

a. Provide the financial analysis and other information that supports Mr. Bleckman's conclusion.

b. Provide any documentation from any of the credit rating agencies that states the 10.25% ROE and 51.5% equity ratio are required to maintain the Company's credit ratings or that the current regulatory ROE and equity ratio metrics are problematic relative to maintaining existing credit ratings.

Response:

a. Not applicable. Rating agencies have FFO to debt ranges that they expect the Company to maintain based on its current risk category / credit rating. While continued underperformance may lead to a ratings downgrade, there is no specific FFO to debt identified that would automatically trigger a negative credit rating action. Though an important consideration, the Company's FFO to debt metric is just one of several qualitative and quantitative measurements that rating agencies consider before taking action on a credit rating. The testimony quoted highlights that a reduction in authorized ROE combined with a lower equity ratio can lead to a deterioration of credit metrics and ultimately a downgrade. This reasoning was validated by Moody's 2021 credit rating downgrade, which specifically pointed to these issues and their associated negative credit metric impacts.

b. Not applicable as there is no such documentation. Refer to response part a.

Witness: MARC R. BLECKMAN
Date: March 1, 2024

VLF*Alert*

Value Line*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.

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Volatility is Not Risk:
Why the Difference is Critical to Long-Term Results

2017 lulled many equity investors into a comfort zone based on historically low volatility. 2018 has been more volatile—with tighter monetary policy and geopolitical and trade policy uncertainty among the drivers of the increase. But volatility levels in 2018 are actually historically normal—even with the bouts of volatility anticipated ahead of the November mid-term elections. But volatility is not risk. And recognizing the difference can be critical to your long-term investment returns.

Defining Our Terms

Volatility is simply the measure of the up and down movements of the market. For example, since 1950, when the Value Line Funds were first established, the average maximum drawdown in the broad U.S. equity market during midterm election years has been -17%, with weakness tending to be concentrated in the pre-election days. However, the good news is that there has been a consistent tendency historically for post-drawdown rallies, averaging +32% in the subsequent year.[1] Volatility? Yes! Uncertainty? Yes! But volatility is only risk if you act during down times—that is, only if you sell. To which the often-invoked quip may well be the most prudent answer: "Don't just do something, sit there."

Risk, on the other hand, is the probability of a permanent loss. You might think of risk as the possibility of having to lower your quality of life in the future.

> **"Volatility is not synonymous of risk but—for those who truly understand it—of wealth."**
>
> *- Francois Rochon**

Recognizing the Difference

Volatility is independent of risk. Too many investors let an investment's short-term price movements, or perceptions of short-term price movements, drive their buying and selling decisions. Too often volatility is regarded as something to be avoided. But since short-term price moves are unknowable and independent of underlying fundamentals and value, such volatility should not be a determinant.

And ALL investments have risk of some kind, including cash and CDs. One just needs to pick the risks that are best to take based on your individual tolerance level, time horizon and financial needs and goals.

As famed investor and Berkshire Hathaway CEO Warren Buffet wrote:

> "Stock prices will always be far more *volatile* than cash-equivalent holdings. *Over the long term*, however, currency-denominated instruments are *riskier* investments — far riskier investments — than widely-diversified stock portfolios that are bought over time and that are owned in a manner invoking only token fees and commissions. **That lesson has not customarily been taught in business schools, where volatility is almost universally used as a proxy for risk. Though this pedagogic assumption makes for easy teaching, it is dead wrong: Volatility is *far* from synonymous with risk.** Popular formulas that equate the two terms lead students, investors and CEOs astray."[2]

> **"Volatility is our friend. Volatility has nothing to do with risk."**
>
> *- Mohnish Pabrai**

(continued on back)

It's a Matter of Time, Not Timing

Most experienced investors do not fear volatility, only unrecoverable loss. But most losses, as measured by a day, a week, a quarter or a year, are recoverable over time. Declines in principal value have historically been temporary. Of course, there are true risks. A company could go totally out of business. An innovation could transform an industry so profoundly to make a once "blue chip" company a relic. A geopolitical event could happen to negate all assumptions. But these occurrences are rare. For the vast majority of investors, maintaining a long-term perspective is the real key to attaining gains over their investing lifetime. Historically, since World War II, the longer you hold stocks, the narrower the range of returns.[3] In other words, even if volatility is a concern, it decreases the longer you hold stocks. It's the old adage: what matters is time in the market, not market timing.

"You can't overlook the volatility, but you don't let it push you around in the market."

*- Boone Pickens**

solutions designed to meet a broad array of investment goals. Whether you are looking for income or long-term capital appreciation, whether you choose to invest in equities, taxabl or tax-exempt fixed income or a hybrid fund of multiple asset classes, you can rely on the solid fundamentals of Value Line Funds.

Value Line Funds Include:
Equity Funds
Premier Growth Fund
Larger Companies Focused Fund
Mid Cap Focused Fund
Small Cap Opportunities Fund
Hybrid Funds
Asset Allocation Fund
Capital Appreciation Fund
Fixed Income Funds
Tax Exempt Fund
Core Bond Fund

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Comparison of Gas Sales Volumes - 2017-2022 Actuals to Sep 2024 Test Year Forecast

Exhibit AG-57
Case No. U-21490
Date: April 22, 2024

		Actual								Test Year 12 Months Ended	2020-2023	2018-2023
Line	Description	2018	2019	2020	2021	2022	2023	2024F	2025F	Sep 2025F	3-YR CAGR	5-YR CAGR
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(k)
1	**Average Gas Use Per Customer (Mcf):** [1]											
2	**Residential Sales**	95.92	97.69	98.01	94.61	94.42	93.97	93.00	92.43	92.57		
3	*Percent Change from Prior Yr*		*1.8%*	*0.3%*	*-3.5%*	*-0.2%*	*-0.5%*	*-1.0%*	*-0.6%*	*-1.5%*	**-1.4%**	**-0.4%**
4	**Commercial Sales**	447.71	453.03	417.56	435.32	436.93	438.58	427.05	424.24	424.85		
5	*Percent Change from Prior Yr*		*1.2%*	*-7.8%*	*4.3%*	*0.4%*	*0.4%*	*-2.6%*	*-0.7%*	*-3.1%*	**1.7%**	**-0.4%**
	Industrial Sales [2]	1,890.12	1,889.75	1,879.44	1,973.80	2,063.53	2,048.54	2,292.43	2,261.63	2,268.62		
	Percent Change from Prior Yr		*0.0%*	*-0.5%*	*5.0%*	*4.5%*	*-0.7%*	*11.9%*	*-1.3%*	*10.7%*	**2.9%**	**1.6%**
	Residential Transport	6,662.98	6,519.77	6,298.85	5,669.95	5,545.00	5,154.59	6,657.05	6,622.22	6,627.20		
	Percent Change from Prior Yr		*-2.1%*	*-3.4%*	*-10.0%*	*-2.2%*	*-7.0%*	*29.1%*	*-0.5%*	*28.6%*	**-6.5%**	**-5.0%**
	Commercial Transport	9,425.30	9,772.92	9,310.27	9,825.26	9,610.38	9,754.86	8,969.42	8,936.23	8,937.90		
	Percent Change from Prior Yr		*3.7%*	*-4.7%*	*5.5%*	*-2.2%*	*1.5%*	*-8.1%*	*-0.4%*	*-8.4%*	**1.6%**	**0.7%**
	Industrial Transport [2]	96,787.93	98,630.89	92,600.38	97,739.70	108,211.21	108,656.07	118,188.13	117,645.73	117,511.52		
	Percent Change from Prior Yr		*1.9%*	*-6.1%*	*5.6%*	*10.7%*	*0.4%*	*8.8%*	*-0.5%*	*8.1%*	**5.5%**	**2.3%**
8	**Gas Deliveries - Weather-Normalized:** [2,3]											
9	**(MMCF)**											
10	Residential Sales	157,608	161,122	163,000	158,188	158,566	158,252	158,023	158,101	158,083		
11	Commercial Sales	55,559	56,514	52,788	55,361	56,078	56,552	55,216	55,022	55,058		
12	Industrial Sales	9,065	8,502	8,200	8,213	8,120	7,639	8,632	8,516	8,542		
13	Residential Transport	1,206	1,154	1,096	1,151	1,109	1,067	1,338	1,331	1,332		
14	Commercial Transport	26,749	27,071	25,566	26,764	26,294	26,582	24,845	24,910	24,885		
15	Industrial Transport [2]	52,943	52,373	48,893	52,193	57,893	58,131	62,973	62,684	62,730		
16	**Average Number of Customers:** [2, 3]											
17	Residential	1,643,100	1,649,303	1,663,158	1,672,062	1,679,345	1,683,983	1,699,201	1,710,562	1,707,692		
18	Commercial	124,097	124,748	126,419	127,173	128,345	128,943	129,295	129,694	129,593		
	Industrial Sales	4,796	4,499	4,363	4,161	3,935	3,729	3,765	3,765	3,765		
	Residential Transport	181	177	174	203	200	207	201	201	201		
	Commercial Transport	2,838	2,770	2,746	2,724	2,736	2,725	2,770	2,788	2,784		
	Industrial Transport	547	531	528	534	535	535	533	533	534		

Source:

(1) Calculated by dividing weather-normalized deliveries by number of customers for Residential and Commercial gas deliveries

(3) Part III Attachment 16 for forecasted 2024 and 2025 gas deliveries and number of customers. DR AG-CE-0337 for W/N historical data

(4) Exhibit A-15 (EJK-6) Schedule E-2 for test year September 2025 gas deliveries and customers.

Question:

176. Refer to page 5 of Mr. Keaton's direct testimony. Please:

a. Provide a copy of each of the forecast models in Excel with formulas intact along with the inputs and outputs.

b. Provide any adjustments made outside of the regression models, such as EWR, showing the calculations and assumptions in Excel with formulas intact.

c. Explain what adjustments were made to the sales forecast or sales forecast model to take into consideration the decline in sales and EUT deliveries during 2020 and 2021 due to the Covid-19 pandemic. Provide those adjustments and calculations in Excel with all assumptions fully explained.

d. Provide the final forecasted sales and transportation volumes with all external adjustments by customer class and rate schedule in Excel.

Response:

a. See WP-EJK-12 for the model statistics and coefficients.

b. See attachment U21490-AG-CE-0335_Keaton_Att_1.xlsx for the adjustments made to the regression results.

c. No adjustments were made to the Gas regression modeling due to the Covid-19 pandemic.

d. See workpaper WP_EJK_8 for the forecasted deliveries by class and rate schedule.

Witness: ERIC J. KEATON
Date: April 10, 2024

U21490-AG-CE-0335_Keaton_Att_1			
Year	Month	ComSlsCyc (MMcf)	ComTrnCyc (MMcf)
2024	10	0	0
2024	11	0	0
2024	12	0	0
2025	1	2,000	-100
2025	2	1,000	200
2025	3	500	400
2025	4	500	400
2025	5	0	350
2025	6	0	-50
2025	7	0	0
2025	8	0	0
2025	9	0	0
	total	4,002	1,200

Incremental Revenue from Higher Residential Sales Volume for Forecasted Test Year

Line #	(a)	(b)	(c)	
1	Average Sales per Customer - Actual 2023 [1]		93.97	Mcf
2				
3	3-Year average rate of change in Usage per Customer [1]	-0.40%		
4				
5	Average Sales per Customer - September 2024 [2]		93.69	Mcf
6				
7	Average Sales per Customer - September 2025 [3]		93.32	Mcf
8				
9	Forecasted Test Year average number of customers [4]		1,707,692	
10				
11	AG Forecasted Sales (Line 7 x Line 9)		159,358,651	Mcf
12				
13	CECo Forecasted Sales [4]		158,083,319	Mcf
14				
15	Increase in Gas Sales (Line 13 - Line 11)		1,275,332	Mcf
16				
17	Current Sistribution Rate A per Mcf [5]		$ 5.2191	
18				
19	**Incremental Rate A Revenue**		**$ 6,656,084**	

Source: (1) Exhibit AG-57.
(2) Line 1 x 9/12 of Line 3 (Represents the rate change in usage from January 2024 to September 2024.
(3) Line 5 x Line 3 (Represents a full year of rate change in usage).
(4) Exhibit A-15 (EJK-6), Schedule E1, line 26, column (c).
(5) Exhibit A-16, Schedule F3, page 1.

Incremental Revenue from Higher Commerical Sales Volume for Forecasted Test Year

Line #	(a)	(b)	(c)				
1	Average Sales per Customer - Actual 2023 [1]		438.58	Mcf			
2							
3	3-Year average rate of change in Usage per Customer [1]	-0.40%					
4							
5	Average Sales per Customer - September 2024 [2]		437.27	Mcf			
6							
7	Average Sales per Customer - September 2025 [3]		435.52	Mcf			
8							
9	Forecasted Test Year average number of customers [4]		129,593				
10							
11	AG Forecasted Sales (Line 7 x Line 9)		56,439,820	Mcf			
12							
13	CECo Forecasted Sales [4]		53,874,000	Mcf	GS-1 [5]	GS-2 [5]	GS-3 [5]
14					49.95%	40.24%	9.81%
15	Increase in Gas Sales (Line 13 - Line 11)		2,565,820	Mcf	1,281,610	1,032,425	251,736
16							
17	Current Rate Comm per Mcf [6]				$ 4.5946	$ 3.2016	$ 2.8990
18							
19	**Incremental Commercial Sales Revenue**		**$ 9,923,678**		$ 5,888,484	$3,305,411	$ 729,783

Source: (1) Exhibit AG-57.
(2) Line 1 x 9/12 of Line 3 (Represents the rate change in usage from January 2023 to September 2023.
(3) Line 5 x Line 3 (Represents a full year of rate change in usage).
(4) Exhibit A-15 (EJK-6), Schedule E1, line 26, column (d).
(5) Allocation to each rate schedule based on DR AG-CE-0339 ATT1
(6) Exhibit A-16, Schedule F3, pages 3 and 4, average of GS-1, GS-2, and GS-3 Distribution rates.

Incremental Revenue from Higher Commerical Transportation Volume for Forecasted Test Year

Line #	(a)						(b)	(c)	
1	Average Transport Volumes per Customer - Actual 2023 [1]							9,754.86	Mcf
2									
3	3-Year average rate of change in Usage per Customer [1]						0.70%		
4									
5	Average Transport Volumes per Customer - September 2024 [2]							9,806.08	Mcf
6									
7	Average Transport Volumes per Customer - September 2025 [3]							9,874.72	Mcf
8									
9	Forecasted Test Year average number of customers [4]							2,784	
10									
11	AG Forecasted Volumes (Line 7 x Line 9)							27,493,288	Mcf
12									
13	CECo Forecasted Transport Volumes [4]							24,885,000	Mcf
14									
15	Increase in Sales Volumes (Line 13 - Line 11)							2,608,288	Mcf
16									
17	GS-1	GS-2	GS-3	GL	ST	LT	XLT	Total	
18	0.85%	8.29%	0.84%	-	43.92%	34.20%	11.90%	100%	Note (5)
19									
20	22,230	216,133	21,890		1,145,686	891,929	310,420	2,608,288	Mcf
21									
22	$ 4.5946	$ 3.2016	$ 2.8990		$ 1.7140	$ 1.4025	$ 1.0617		Current Rate Comm per Mcf [6]
23									
24	$ 102,137	$ 691,971	$ 63,458	$ -	$ 1,963,707	$ 1,250,931	$ 329,573	**$ 4,401,777**	**Incremental Revenue**

Source: (1) Exhibit AG-58.
(2) Line 1 x 9/12 of Line 3 (Represents the rate change in usage from January 2023 to September 2023.
(3) Line 5 x Line 3 (Represents a full year of rate change in usage).
(4) Exhibit A-15 (EJK-6), Schedule E1, line 26, column (d).
(5) Allocation to each rate schedule based on DR AG-CE-0339 ATT1
(6) Exhibit A-16, Schedule F3, Distribution rate for each rate schedule.

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-21490**
Consumers Energy Company - Gas Rate Case **Exhibit AG-60**
Date: April 22, 2024
Operations & Maintenance - Summary **Page 1 of 1**

Line	Description (a)	Millions of Dollars (b)	Note or Ref. (c)
1	**O&M Per Company Case**	$ 277.8	*
	Attorney General Changes		
2	Gas Operations - Staking and Locating Program	(3.1)	Testimony
3	Gas Engineering and Supply - Effect of Reorganization	(4.9)	WP AG-60A
4	Transmission Pipeline Integrity	(10.7)	Testimony
5	Information Technology	(2.5)	Testimony
6	Uncollectibles Expense - Effect of Lower Gas Costs & Other	(0.4)	Exhibit AG-61
7	Company Use Gas & LAUF (Lower Cost of Gas Rate)	(4.5)	Exhibit AG-62
8	Active Health Care	(1.4)	Exhibit AG-63
9	401(k) Employee Savings Plan	(0.9)	Exhibit AG-64
10	Corporate Services and Other	(6.1)	Testimony
11	Incentive Compensation	(0.8)	Testimony
12	**Total Change**	**$ (35.3)**	Sum L2 to L11
13	**AG Revised O & M Level**	**$ 242.5**	L1 + L12
14	**Change in O&M Expense**	**$ (35.3)**	L13 less L1

* Per Company Exhibit A-13 (HLR-41), Sched. C-5, page 1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company - Gas Rate Case

Case No. U-21490
Exhibit AG-61
Date: April 22, 2024
Page 1 of 1

Uncollectible Accounts Expense - Thousands of Dollars

Line	Year (a)	Net Energy Write-offs (b)	Gas Service Revenue (c)	Ratio of Write-offs to Revenue (d)	Source or Note (e)
1	2021	10,760	1,803,406	0.597%	DR AG=CE-157
2	2022	14,260	2,527,764	0.564%	DR AG=CE-157
3	2023	17,234	2,215,687	0.778%	DR AG=CE-157
4	3 Yr. Avg. Loss Ratio			0.646%	Avg Lines 1, 2, 3
	Projected Test Year Revenues				
5	Revenues Per Company			$ 2,455,000	Ex. A-46 (MJF-3), p2, L7
6	Less Lower Cost of Gas			(148,004)	Note 1
7	Revenues Adjusted for lower Cost of Gas			$ 2,306,996	L 5 less L 6
	Uncollectible Accounts Expense				
8	3 Yr. Avg. Loss Ratio			0.646%	Line 4 Above
9	Uncollectibles Per AG Case			$ 14,908	L 7 x L 8
10	Uncollectibles Per Company Case (Per Exh. A-49 (MJF-3))			15,290	Exh. A-46 (MJF-3), p2, L9
11	**O & M Reduction - Uncollectible Accounts Expense**			**$ (382)**	L 9 less L 10

1 Reductions in Revenues Due to a Lower Cost of Gas

Cost of Gas Rate per Company Case (see Exhibit A-83 (TKJ-4))	$ 3.864
Less Cost of Gas Rate Revised by Company (see DR SA-CE-102 Att 1 line 24)	3.197
Cost per MCF reduction	$ 0.667
Percentage Change in Cost of Gas Rate	17.26%
Cost of Gas per Company (see Exhibit A-13 (HLR-40) Sch. C-4	$ 857,400.0
Cost of Gas Reduction (multiply)	**$ 148,003.6** ***To Line 6 Above***

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21490**
Consumers Energy Company - Gas Rate Case | **Exhibit AG-62**
Date: April 22, 2024
Company Use and LAUF Gas - Thousands of Dollars | **Page 1 of 1**

Line	Description or Item (a)	MMcf Volume (b)	Cost of Gas Rate (c)	Cost (d)	Source or Note (e)
	Company Case				
1	Lost & Unaccounted Gas For (LAUF) Volume	3,489.9	$ 3.864	$ 13,483	Ex. A-83 (TKJ-4)
2	Company Use Gas Volume	1,673.4	3.864	6,465	Ex. A-83 (TKJ-4)
3	Total Volume & Cost Per Company	5,163.3	$ 3.864	**19,948**	L 1 + L 2
4	Result of Cost of Gas Rate Reduction Only	5,163.3	$ 3.197	$ 16,507	Note 1
5	Cost of Gas Rate Change		**$ (0.667)**		Rate Change Col (c)
	AG Case Changes				
6	Cost Change Due to Cost Rate Reduction	5,163.3	$ (0.667)	$ (3,441)	L 4 less L 3
7	Reduction of 9.8% in LAUF Volume (National Goal)	(342.0)	$ 3.197	(1,093)	Note 2
8	Total Reduction in Expense			**(4,534)**	L 6 + L 7
9	AG Cost of Company Use & LAUF			**15,414**	L 3 + L 8
10	**Reduction in Co. Use & LAUF Cost and O&M Expense**			**$ (4,534)**	L 9 less L 3

1 The rate change reflects a substantial change in the NYMEX Gas Price Futures.
See DR-SA-CE-102 for Company witness Joyce's revised Cost of Gas rate of $3.197 in Attachment 1, line 24

2 Page 7 of Mr. Stuart's testimony explains the national goal of reaching zero emissions by 2050. From 2022 to 2050 is a period of 28 years suggesting a 3.57% annual reduction over the 28 year period. Using the 3.57% rate times the 2.75 years between the historic and projected test years suggests a 9.8% reduction is appropriate

Active Medical Expenses -Reduced Inflation Rate
(Thousands of Dollars)

Line	Caption	2017	2018	2019	2020	2021	2022	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Historic Cost Information							
1	Total Actual Medical, Dental & Vision	$ 75,320	$ 81,359	$ 84,549	$ 75,705	$ 93,570	$ 92,128	Note 1
2	Avg. Annualized Cost Increase (5 Yrs.)				4.10%			Note 2

Line	Caption		2022	2023	2024	2025	2024-25 TY	
				Base Level Plus Inflation				
	O&M Projected Expense Information		2022	2023	2024	2025	2024-25 TY	
3	Active Medical Alloc. To O & M		15,984	15,984	16,639	17,322		
4	Historical Cost Trend for 12 months at 4.1% (line 2 Above)			655	-	-		
5	Historical Cost Trend for 12 months at 4.1% (line 2 Above)			-	682	710		
6	Base Period + Inflation			$ 16,639	$ 17,322	$ 18,032	17,854	Note 3
7	Less 8.5% Adjustment for Company Downsizing						(1,518)	Note 4

Notes
1 Reflects total Gas and Electric Expenses before allocation to Capital (From U-21308 Discovery Response AG-CE-0332
Costs falling in 2020 and then peaking in 2021 reflects a shifting of medical treatments into 2021 due to COVID 19
2 Annualized compound growth rate for 5.0 years
3 Column (g) reflects 25% of 2024 plus 75% of 2025
4 Page 34 of the Company's 2023 Form 10-K shows employee levels falling from 8,897 in 2022 to 8144 in 2023 (an 8.5% reduction)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21490
Exhibit AG-64
Date: April 22, 2024

401-K Plan Expenses
(Thousands of Dollars)

Line	Company Item or Description	Projected Test Yr. Expense Computed	Notes
1	Actual 2023 Expense Level	$ 6,448	1
2	Inflation at Company Forecasted Rates		
3	2024 Inflation at 2.6%	168	2
4	Sub Total	6,616	L 1 + L3
5	2025 Inflation at 1.65%	109	2
6	Projected Test Year Expense Level	6,725	L 3 + L4
7	Expense Level per Company	7,621	3
8	**Change in Expense Level and O&M**	**$ (896)**	L 6 less L 7

1 Actual 2023 Expense level per AG-CE-401
2 Reflects inflation per Exhibit A-66 (KKG-1) page 2
3 See Exhibit A-66 (KKG-1) page 2, line 3 in the far right column

Question:

25. On page 46 (lines 7 to 10) of his direct testimony, witness Pnacek states that "…based on the existing benefits realized for the Gas Only staking program that was implemented on February 21, 2023, the Company plans to expand the program to now include all of Oakland County, Kent County, Kalamazoo County and Ingham County." Please:

a. Provide a copy of the analysis showing the benefits that were realized in 2023 from the Oakland County Gas-only Staking program and explain how those benefits justify expanding the Gas-only staking program.

b. Explain why the expansion of the Gas Only staking approach is warranted at this time given the limited period of time that the program has been underway in Oakland County.

c. Provide the number of Oakland County staking requests in 2023 conducted via the traditional staking approach versus the Gas-only staking approach. Also provide the dollar amount and number of damage incidents pertaining to each approach.

Response:

The Gas Only Staking program is being referred to as the Dedicate model in this response.

a. Please see attachment U21490-AG-CE-0160_Pnacek_ATT_1.xlsx for the analysis showing the program objectives and the results achieved in 2023 for the Oakland County Dedicate Staking model program compared to the Shared Staking model. The intended benefits of the dedicated model were achieved related to timeliness, quality, and excavator communications. Timeliness improvements included a 2.2% improvement in field timeliness. The field timeliness improvements include an improvement in ticket response which includes improved comments for ongoing coordination related tickets. The excavator communication improvements are through enhanced positive response which provides additional information and pictures to the ticket initiator. Damages related to 'at fault damages'/ 'locator cause damage' decreased by 87.3% (9 in 2023 vs 71 in 2022) when comparing the same area in the prior year. All cause damages in the same area decreased by 24.7% (314 in 2023 vs 417 in 2022). The Dedicated staking model program expansion is justified since these anticipated Public Safety related benefits, which are described on page 46 lines 11-23 and page 47 line 1-13 of my direct testimony, have been met and there is a continued need for improvement in the area of Public Safety in this and other locations.

b. The Company believes the expansion of the Dedicated model approach is warranted at this this time based on the results achieved and discussed in Part a of this question. The fact that these results were achieved quickly shows that the program can have a significant impact on Public Safety in other locations in a short period of time. In addition, with the Electric Staking program adopting a Dedicated staking model, as outlined in Case No. U-21389, this will keep the program county footprint aligned and allow for the Dedicated model locaters to include both Electric and Gas staking.

c. The following table is for Oakland County 2/3 Zone from 2/22/23 thru 12/31/23, is based on the best information available at this time and provides the number of Oakland County staking requests in 2023 conducted via the traditional staking approach (Shared model) versus the Dedicated Gas-only staking approach. The tables also provides the number of 'locator cause' / 'at fault' damages and 'all cause' damage pertaining to each approach. The cost is provided for the Dedicated model approach; however costs are not tracked to the level of the remaining Oakland County footprint for the Shared resource model.

Model	Staking Requests	Locator Cause Damages	All Cause Damages	Cost
Dedicated model	64,235	9	314	$2,766,691
Shared model	37,210	29	194	NA

Witness: James P. Pnacek
Date: March 12, 2024

Dedicated Staking Model Evaluation

Program Objectives	Comparison Location	Comparison	Feb 22-28	March	April	May	June	July	August	Sept	Oct	Nov	Dec	Total	Results	Benefit
Improvement in quality/accuracy to reduce the amount of staking and locating cause related damages in the area of application which includes either facility was not located or marked, facility markings/location not sufficient or late response	Oakland County 2/3 Zone	2022 Locator Cause Damages (Shared model)	0	1	6	4	15	3	18	7	9	7	1	71	**87.3%**	There was a 87.3% reduction of locator cause damages between the Dedicated model compared to the Shared resource model
		2023 Locator Cause Damages (Dedicates model)	0	0	1	3	0	3	0	1	1	0	0	9		
Improvement in quality/accuracy to reduce the amount of overall damages in the area of application.	Oakland County 2/3 Zone	2022 All Cause Damages (Shared model)	0	13	32	51	55	41	69	49	52	38	17	417	**24.7%**	There was a 24.7% reduction of All Cause Damages between the Dedicated model compared to the Shared resource model
		2023 All Cause Damages (Dedicated model)	4	20	19	39	39	35	32	47	27	34	18	314		
Improvement in timeliness by maintaining 98% average or greater field timeliness for all new normal, emergency and 24 hour retransmit tickets.	Statewide to Oakland County 2/3 Zone	Shared Model Timeliness (2023 Statewide)	NA	96.9%	98.1%	95.5%	97.1%	97.5%	97.3%	96.5%	96.2%	97.2%	95.9%	96.8%	**2.2%**	There was a 2.0% improvement in timeliness for 2023 between the Dedicated model to the Statewide Shared resource model
		Dedicated Model Timeliness (2023 Oakland County 2/3 Zone)	NA	97.9%	94.5%	99.1%	99.9%	99.6%	99.8%	99.9%	99.9%	99.8%	99.6%	99.0%		

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

Question:

26. Provide a list of names of other gas utilities that have implemented Gas-only Staking and provide any information obtained from these companies or industry groups documenting the benefits and/or cost savings of this type of program.

Response:

The Company did not contact or obtain information from other gas utilities regarding the Dedicated Staking Model (formerly referred to as Gas Only Staking). Page 46 line 12 to page 47 line 13 of my direct testimony discusses the benefits of the Dedicated Staking Model which are to improve timeliness and accuracy of staking for the benefit of public safety.

Witness: James P. Pnacek
Date: March 12, 2024

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

Question:

27. Regarding Gas-only staking, Mr. Pnacek on page 49 of his direct testimony starting at line 6 states "at fault damages have improved 85%" and that "the number of damages in this area have decreased 26%". Please:

a. Explain what is meant by "at fault damages have improved 85%" and provide the data supporting the 85% improvement. Also provide a comparison of at fault damages in Oakland County versus each of the other areas in each year 2018 to 2023 in Excel.

b. Provide the data and calculations that show reduced damages of 26% in comparison to each of the other areas in Excel during the same time period.

Response:

In response to this question, tables and data will be provided in the excel attachment U21490-AG-CE-0162_Pnacek_ATT_1.xlsx. Each request will be provided on its own individual tab as indicated below. Please note the data provided for comparison is from 2019-2023. Prior to 2019, the data was not broken down by county. Also, the Gas Only Staking program is being referred to as the Dedicate model in this response.

a. As referenced on page 49, line 5 and 6, of my direct testimony, "accuracy related to at fault damages have improved by 85%" means that improvements in quality/accuracy to reduce the amount of staking and locating cause related damages in the area of application which includes either the facility was not located or marked, facility markings/location not sufficient or late response has resulted in a reduction of 85% of the at fault damages.

   The 85% improvement provided on page 49, line 6, of my direct testimony was based on data and calculations through the end of September 2023 and is shown on tab 'Part a subpart 1'. In addition, this table has also been updated to include data and calculations through the end of 2023. The table includes the data and calculation that shows the accuracy related to 'at fault damages' had improved by 87.3% at the end of 2023.

   In addition, on tab 'Part a subpart 2' is 2019-2023 data by county that shows the number of 'at fault damages' / 'locate contractor fault' for comparison.

b. The 26% reduction provided on page 49, line 7, of my direct testimony was based on data and calculations through the end of September 2023 and is shown on tab 'Part b subpart 1'. Please note that the end of September 2023 data shows a 24.2% reduction vs the 26% reduction of 'all cause damages' in my testimony because Feb 22-28, 2023, data was missing from the testimony calculation. In addition, this table has been updated to include data and calculations through the end of 2023. The table includes the data and calculation that shows there was a decrease in the number of 'all cause damages' by 24.7% at the end of 2023.

   In addition, on tab 'Part b subpart 2'is 2019-2023 data by county that shows the number of 'all cause damages' for comparison.

Witness: James P. Pnacek
Date: March 12, 2024

Oakland County 2/3 Zone	Feb 22-28	March	April	May	June	July	August	Sept	Oct	Nov	Dec	Total		End of Sept	End of 2023
2022 Actual Locator Cause Damages (Shared model)	0	1	6	4	15	3	18	7	9	7	1	71			
2023 Actual Locator Cause Damages (Dedicated model)	0	0	1	3	0	3	0	1	1	0	0	9		85.2%	87.3%
% reduction in the number of locator cause damages from 2022 to 2023															

3rd Party Gas UG Damages w/Locate Contractor Fault - ALL Counties						
County	2018	2019	2020	2021	2022	2023
Oakland (ALL)	NA	98	59	63	106	38
Oakland (Dedicated Area)	NA	NA	NA	NA	71	9
Macomb	NA	38	40	28	33	30
Kalamazoo	NA	28	31	23	35	45
Ingham	NA	22	33	17	26	34
Wayne	NA	20	30	13	10	7
Genesee	NA	28	12	4	13	20
Livingston	NA	6	8	13	16	12
Kent	NA	7	10	3	0	8
Lapeer	NA	6	3	5	6	6
Eaton	NA	4	4	4	3	9
Saginaw	NA	7	2	7	4	3
Jackson	NA	6	6	2	5	4
Shiawassee	NA	4	1	4	5	7
Clinton	NA	3	3	4	1	10
Ionia	NA	6	0	1	10	3
Van Buren	NA	4	3	2	6	5
Barry	NA	4	2	1	3	4
Midland	NA	4	2	1	0	4
Calhoun	NA	2	2	3	2	0
Lenawee	NA	1	1	4	0	2
Gratiot	NA	0	4	3	1	0
Missaukee	NA	0	0	3	2	3
Allegan	NA	1	2	1	2	0
Isabella	NA	0	2	2	1	0
Mecosta	NA	1	0	3	1	0
Washtenaw	NA	1	1	1	0	1
Bay	NA	1	0	0	1	2
Gladwin	NA	0	0	2	2	0
Saint Clair	NA	0	1	0	2	0
Tuscola	NA	0	1	1	1	0
Hillsdale	NA	0	0	0	0	3
Huron	NA	1	1	0	0	1
Arenac	NA	0	0	0	1	1
Montcalm	NA	0	0	0	0	2
Monroe	NA	0	0	0	1	0
Kalkaska	NA	0	0	0	1	0
Osceola	NA	1	0	0	0	0
		304	**264**	**218**	**371**	**273**

Oakland County 2/3 Zone	Feb 22-28	March	April	May	June	July	August	Sept	Oct	Nov	Dec	Total		End of Sept	End of 2023
2022 Actual All Cause Damages (Shared Model)	0	13	32	51	55	41	69	49	52	38	17	417			
2023 Actual All Cause Damages (Dedicated model)	4	20	19	39	39	35	32	47	27	34	18	314		24.2%	24.7%
% Reduction in the number of all cause damages from 2022 to 2023															

1st/2nd/3rd Party Gas UG Damages by County - ALL

County	2018	2019	2020	2021	2022	2023
Oakland (ALL)	NA	734	732	641	673	539
Oakland (Dedicated Area)	NA	NA	NA	NA	417	314
Macomb	NA	256	293	229	224	229
Genesee	NA	185	202	136	179	174
Kalamazoo	NA	143	129	143	165	144
Ingham	NA	119	117	127	146	150
Wayne	NA	111	117	97	111	76
Livingston	NA	78	98	95	112	87
Saginaw	NA	59	57	76	63	63
Jackson	NA	62	72	60	50	40
Bay	NA	58	27	24	53	50
Midland	NA	35	51	29	28	44
Lapeer	NA	47	31	32	28	37
Kent	NA	31	35	32	19	29
Eaton	NA	13	25	32	23	42
Van Buren	NA	17	23	27	24	36
Ionia	NA	25	17	17	40	26
Shiawassee	NA	18	17	35	30	24
Lenawee	NA	14	19	21	36	33
Barry	NA	21	20	16	19	18
Gratiot	NA	16	22	23	16	15
Clinton	NA	14	20	15	10	23
Huron	NA	17	18	16	13	10
Gladwin	NA	11	14	21	16	7
Isabella	NA	16	11	9	11	14
Washtenaw	NA	9	22	11	8	6
Tuscola	NA	13	15	5	7	7
Mecosta	NA	4	4	16	13	7
Calhoun	NA	8	8	7	13	7
Allegan	NA	8	7	13	8	4
Montcalm	NA	3	12	11	6	6
Arenac	NA	6	4	6	13	5
Missaukee	NA	4	1	10	5	8
Saint Clair	NA	0	3	0	4	2
Hillsdale	NA	2	2	0	0	4
Branch	NA	1	2	1	2	1
Iosco	NA	3	0	1	1	2
Cass	NA	0	0	1	0	4
Osceola	NA	4	0	0	1	0
Monroe	NA	1	2	0	2	0
Kalkaska	NA	0	1	1	3	0
Saint Joseph	NA	0	0	0	1	1
Ottawa	NA	1	0	0	0	0
St Clair	NA	0	0	1	0	0
Leelanau	NA	0	1	0	0	0
Sanilac	NA	1	0	0	0	0
		2,168	**2,251**	**2,037**	**2,593**	**2,288**

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Question:

248. Refer to the response to AG-CE-160. Please explain the reason for the name change to "Dedicated." Does it indicate an expansion of the program to include more than gas staking requests? Explain fully.

Response:

The Gas Only Staking and the Electric Only Staking programs, under which contractors work solely for the Company, are both being referred to as the "Dedicated Staking Program/Model". In combination areas, Consumers Energy's Gas and Electric staking, under these programs, is intended to occur during the same site visit. The Gas and Electric Staking Only programs are aligned to expand into the same counties during 2024 and 2025.

Witness: James P. Pnacek
Date: April 4, 2024

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Question:

266. Refer to the response to AG-CE-0160. Subpart (c) shows a cost for the Dedicated model but no cost for the traditional Shared model. Please provide the cost for the Shared model or explain the logic for further expansion of the dedicated staking approach to other areas given that no relative cost justification to the Shared model has been provided.

Response:

As previously state in response AG-CE-0160, "The cost is provided for the Dedicated model approach; however, costs are not tracked to the level of the remaining Oakland County footprint for the Shared resource model." With that said, an estimated cost is being provided for the table in AG-CE-0160 based on a statewide average unit cost without penalties for the shared model.

Model	Location	Staking Requests	Locator Cause Damages	All Cause Damages	Cost
Dedicated model	2/3 of Oakland County under Dedicated program	64,235	9	314	$2,766,691 Actuals
Shared model	Remaining 1/3 of Oakland County under the shared model	37,210	29	194	$951,088 est Estimated Based on a statewide average unit cost for the shared model

Staking is a Public Safety program, and the Company is moving toward a Dedicated Staking Program model that is primarily intended to yield public safety benefits. The response to U21490-AG-CE-0160 subpart a and b provided the justification for further expansion of the dedicated staking approach and showed the success in achieving the intended benefits of the dedicated model related to timeliness, quality, and excavator communications. The objective of the dedicated staking program have been met and there is a continued need for improvement in the area of Public Safety in other locations. The Company believes the expansion of the Dedicated model approach is warranted at this this time based on the results achieved. The fact that these results were achieved quickly shows that the program can have a significant impact on Public Safety in other locations in a short period of time.

Witness: James P. Pnacek
Date: April 10, 2024

Question:

185. Refer to lines 13 to 23 on page 12 of Ms. Pascarello's direct testimony on Gas Project Management and the Quality Lean department. Please:

a. Provide a list of the process improvements and work efficiencies achieved by the Quality Lean department during the three-year period 2021 to 2023, and projected for 2024 and 2025 with the related cost savings.

b. Provide a reference where the cost savings are shown the various exhibits by department and line number.

Response:

a. As described on page 12 of my direct testimony, the Quality Lean Department does not itself achieve the improvements, but provides support to other Company personnel. This department provides learning and development on Lean methodologies and tools as well as facilitates problem solving, value stream assessments, etc. to identify opportunities for process improvements. These process improvements can help to control and at times lower overall costs.

b. The overall O&M reductions for this case are shown in Exhibit A-13 (HLR-42), column (h). Lines 1, 2, 3, 5, and 6 represent the expenses for the Gas Operations, and Gas Engineering and Supply organizations. While Consumers Energy has not calculated the requested O&M savings resulting from the support from the Quality Lean Department, any ongoing savings achieved with support from the Quality Lean Department would be included in the totals provided in this exhibit. Please note that O&M cost savings in a particular business area do not necessarily indicate a one-to-one reduction in O&M expenses in current or projected years for that area. For example, O&M savings may offset other cost increases, offset funding needed in other areas of the business, or represent one-time savings that are not repeatable on a going forward basis.

Witness: Kristine A. Pascarello
Date: April 11, 2024

Consumers Energy Company
Summary of Inflation and Merit Increases Included in Operation and Maintenance Expenses
For the Projected 12-Month Period Ending September 30, 2025
($000)

Exhibit No.: A-13 (HLR-42)
Schedule: C-5.1
Page: 1 of 1
Witness: HLRayl
Date: December 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
				Projected Adjustments					
Line No.	Description	Source	Historical O&M for the 12 Months Ended 12/31/2022	Inflation & Merit for the 12 Months Ended 12/31/2023	Inflation & Merit for the 12 Months Ended 12/31/2024	Inflation & Merit for the 9 Months Ended 9/30/2025	Other Adjustments	Total Projected Adjustments	Projected O&M for the 12 Months Ended 9/30/2025
								∑ (d) thru (g)	(c) + (h)
1	Gas Operations	Exhibit No.: A-102 (JPP-2)	130,251	3,475	2,219	1,520	(30,853)	(23,639)	106,612
2	Gas Engineering & Supply	Exhibit No.: A-95 (KAP-2)	13,930	585	392	268	6,861	8,106	22,036
3	Transmission	Exhibit No.: A-55 (MPG-1)	3,289	129	87	59	333	608	3,897
4	Operations Support	Exhibit No.: A-70 (QAG-2)	10,785	111	63	43	(1,477)	(1,260)	9,525
5	Pipeline Integrity	Exhibit No.: A-55 (MPG-1)	20,342	830	556	381	1,790	3,557	23,899
6	Gas Compression Storage	Exhibit No.: A-80 (TKJ-1)	23,830	764	512	350	(8,417)	(6,791)	17,039
7	LAUF	Exhibit No.: A-81 (TKJ-2)	27,492	-	-	-	(14,009)	(14,009)	13,483
8	Company Use Gas	Exhibit No.: A-81 (TKJ-2)	(651)	-	-	-	7,116	7,116	6,465
9	Customer Experience & Operations	Exhibit No.: A-91 (SQM-2)	42,650	1,791	1,200	822	(12,792)	(8,979)	33,671
10	Information Technology - Operations	Exhibit No.: A-17 (SHB-1)	25,858	266	178	122	(1,189)	(623)	25,235
11	Information Technology - Investments	Exhibit No.: A-19 (SHB-3)	6,869	-	-	-	(230)	(230)	6,639
12	Information Technology - Security - Operations	Exhibit No.: A-28 (BSB-3)	4,651	68	46	31	(412)	(267)	4,384
13	Information Technology - Security - Investments	Exhibit No.: A-29 (BSB-4)	734	-	-	-	(155)	(155)	579
14	Pension Plans A/B	Exhibit No.: A-66 (KKG-1)	(21,515)	(904)	(605)	(414)	(6,143)	(8,066)	(29,581)
15	Defined Company Contribution Plan	Exhibit No.: A-66 (KKG-1)	7,509	315	211	145	101	772	8,281
16	401(k) Employees' Savings Plan	Exhibit No.: A-66 (KKG-1)	6,908	290	194	133	95	713	7,621
17	Active Health Care/ Insurance/ LTD	Exhibit No.: A-66 (KKG-1)	15,984	671	450	308	334	1,763	17,747
18	Retiree Health Care and Life Insurance	Exhibit No.: A-66 (KKG-1)	(52,795)	(2,217)	(1,485)	(1,017)	24,861	20,141	(32,654)
19	Other Benefits	Exhibit No.: A-66 (KKG-1)	2,409	101	68	46	409	624	3,033
20	Incentive Compensation	Exhibit No.: A-42 (AMC-3)	1,519	59	40	27	(136)	(11)	1,508
21	Corporate Services	Exhibit No.: A-45 (MJF-2)	27,155	1,140	764	523	-	2,428	29,582
22	Uncollectible Expense	Exhibit No.: A-44 (MJF-1)	14,260	-	-	-	1,030	1,030	15,290
23	Injuries & Damages	Exhibit No.: A-44 (MJF-1)	2,310	-	-	-	59	59	2,369
24	MGP - Direct Projected Management Costs	Exhibit No.: A-44 (MJF-1)	733	-	-	-	148	148	881
25	Jobwork expenses	WP-HLR-11	158	-	-	-	(130)	(130)	29
26	ASP expenses	WP-HLR-11	53,443	-	-	-	(53,443)	(53,443)	-
27	Interest expense on security deposits	WP-HLR-17	143	-	-	-	-	-	143
28	Total operation and maintenance expenses	Sum Lines 1 - 27	368,251	7,475	4,889	3,346	(86,247)	(70,537)	297,713
29	Less: LAUF	Line 7	27,492	-	-	-	(14,009)	(14,009)	13,483
30	Less: Company Use Gas	Line 8	(651)	-	-	-	7,116	7,116	6,465
31	Net operation and maintenance expenses	Line 28 - Line 29 - Line 30	341,410	7,475	4,889	3,346	(79,355)	(63,645)	277,765

Question:

189. Refer to lines 8-23 on page 18 of Ms. Pascarello's direct testimony on the SIMP. Please:

a. Identify what the $5.3 million will be spent on in detail.

b. Provide the number of employees and contractors, separately, that will be working on the program and what specifically they will be doing.

c. Provide the expense for each year 2021 to 2023 actual and forecasted for 2024 and 2025 with the related work units.

d. Explain and justify why the forecasted level of activity in 2024, 2025, and the projected test year is required and why this work cannot be ramped up more gradually and spread over multiple years.

Response:

a. Please see attachment U21490-ST-CE-0109_Pascarello_ATT_1.

b. The $5.3 million for the SIMP represents the program work only.

c.

	Estimated Company Employees	Company Emp. Responsibilities	Estimated Contractors	Contractor Responsibilities
Well Plugging (Monitoring)	3 to 5	Technicians - doing physical or drone survey (2), 1 to prepare reports and records. Engineer to review results.	2	Real Estate Field Agents to secure access rights to 3rd Party Wells.
Atmospheric Corrosion	1	Project Management support (cost, schedule, admin)	3 to 4	Surface preparation (taping/blasting), painting, inspection
Risk Reduction	2 to 5	Engineers and technicians to review records, order/conduct field investigations, write test plans, evaluate risk, and record compliance. Internal crews may be utilized to investigate, test, or replace/repair depending on scope and availability.	3 to 6	Will vary significantly depending on remediation needed - testing, replacement, etc. Contractors will also support field investigation and conduct repairs, replacements, or testing.
Annular Pressure Remediation	4 to 6	Engineers to review annulus pressure readings, review test results, prescribe repairs, and depending on the extent of the remediation internal crew to make repairs. Project Management support.	11 +	Service rig and support services will require 11 contractors to work over a well, 12 with coil tubing. This includes all services and oversight.
Well Re-Assessment	2 to 4	Engineers review logging results and make determination, technician captures for records, project management support.	4	Logging Engineer, Mechanic, and driver
Gas Storage Field Analysis	1 to 3	Engineers and Manager to scope, support with operational data collection and support through the analysis.	2 to 4	Depending on the contractor bids the job, likely engineers, technicians, and someone to manage the projects

		12 Mos Ending Dec 31, 2022	12 Mos Ending Dec 31, 2023	Projected 12 Mos Ending Dec 31, 2024	Projected 12 Mos Ending Dec 31, 2025
Storage Integrity Management Program ("SIMP") ($000)		**$629**	**$630**	**$4,619**	**$5,619**
a) Well Plugging Program		$29	$22	$419	$506
	Units: # of CE Plugged Wells	74	85	85	86
	Units: # of 3rd Party Plugged Wells	0	0	93	120
b) Atmospheric Corrosion Protection (Painting) of Rehabilitated Wells		$293	$126	$363	$378
	Units: # of Wells Painted	15	25	53	52
c) Risk Reduction		$285	$184	$2,265	$2,265
	Units: # of Farm Taps	11	30	60	60
	Units: # of Storage Fields: Storage Lateral/Well Line (pi;	2	1	4	4
d) Annular Pressure Remediation		$21	$94	$466	$480
	Units: # of Wells (Assumes 30 Wells w/ wellhead seal replacements on casing only wells, 6 Wells w/ wellhead seal replacements that have tubing)	3	13	36	36
e) Well Re-assessment			$48	$905	$1,775
	Units: # of Wells	0	0	110	111
f) Gas Storage Field Analysis			$158	$200	$214
	Units: # of Storage Fields	0	1	2	2

d. The contributors to the increase in spend are mostly associated with increases in spend in the areas of Risk Reduction, Well Re-Assessment, and Plugged Well Monitoring. The Risk Reduction increases are associated with addressing MAOP reconfirmation of storage lateral pipeline segments and addressing risk with the Farm Tap Setups. This spend is intended to address these areas over a three-year period. The Well Re-Assessment started in 2024 as a requirement of the SIMP as the wells in scope for 2024 were baseline assessed in 2017 under the Well Rehabilitation Program. The Well Re-Assessment is an ongoing and required inspection on a mandated 7-year cycle. The spending on the Plugged Well Monitoring Program is increasing due to the requirement to monitor plugged wells, including 3rd Party Wells. 2024 will be the first year that the Company is starting monitoring of the 3rd Party Plugged Wells. The reasons for the higher cost to monitor 3rd Party Plugged Wells are explained in response U21490-ST-CE-0116. The Company's spending plans are based on the programs to ensure delivery of the Company's responsibility to comply with Federal and State requirements for operating a safe natural gas storage system.

Witness: Kristine A. Pascarello
Date: April 11, 2024

	U21490-ST-CE-0109_ATT_1					
MICHIGAN PUBLIC SERVICE COMMISSION					Case No.:	U-21490
Consumers Energy Company					Exhibit No.:	A-95 (KAP-2)
SIMP Details					Page:	11 of 11
					Witness:	KAPascarello
($000)					Date:	February 2024
						Projected
						12-Mos Ending
						Sep 30, 2025
1		**Storage Integrity Management Program ("SIMP")**				**5,341**
		a) Well Plugging Program				233
		b) Atmospheric Corrosion Protection (Painting) (				375
		c) Risk Reduction				2,265
		d) Annular Pressure Remediation				479
		e) Well Re-assessment				1,775
		f) Gas Storage Field Analysis				214

Question:

190. Refer to lines 12-17 on page 20 of Ms. Pascarello's direct testimony on the SIMP. Please

a. Explain why records validation, field research, physical verification, etc. was not taking place before SIMP as a matter of course in operating those facilities.

b. Identify specifically what the $2,265,000 will be spent on.

c. Provide the amount spent on these functions during each year 2021 through 2023.

Response:

a. The facilities installed and included under the risk reduction portion of this funding requirement were designed and constructed prior to current regulatory requirements and industry standards. This portion of the funding is to investigate, validate, and remediate risk associated with the gas storage system that covers scope not included elsewhere in SIMP or other storage related program funding.

b. The $2,265,000 will be spent on addressing design, construction, and documentation risk. The facilities installed and included under the risk reduction portion of this budget were designed and constructed prior to current regulatory requirements and industry standards. This pertains primarily to the farm taps on the system which were largely unregulated at the time of installation. The risk reduction is primarily to address modern design and construction requirements related to gas quality, construction material, odorization, and over-pressure protection. Additionally, new regulatory requirements to establish MAOP reconfirmation are required from older installations that may not have been captured at the time of the original construction. This portion of the risk reduction is researching the archived records, including field verification, to establish complete records. Replacing, retiring, or retesting components or assemblies may also need to be completed if sufficient documentation is not available.

c. The Company began the SIMP risk reduction in 2021 to establish this portion of the program. The expenses in this portion of the SIMP program were $0, $131,389, and $183,524 each year 2021 through 2023, respectively.

Witness: Kristine A. Pascarello
Date: April 8, 2024

U21490-AG-CE-0341
Page **1** of **1**

Question:

182. In conjunction with the Company's recent corporate reorganization and employee reduction initiative, please provide the following information in Excel for total company and the portion applicable to the gas business:

a. Provide the number of total employee reductions, and by department, with related cost reductions for 2023, 2024, and 2025.

b. Provide the information in subpart (a) separately for labor cost savings, savings in employee benefits, space and other overhead costs for each year.

c. Identify in which exhibit and line number the cost savings are shown for each department, or overall, for each year 2023-2025, and for the projected test year, and the specific amount.

Response:

a. Please refer to Attachment U21490-AG-CE-0341-Myers_ATT_1 for the number of total employee reductions and associated cost savings for 2023, 2024, and 2025. For the Security line item, while there were savings within Security through the reduction of staff in 2023, Security also added Fusion Center staff in late 2023 resulting in a net increase as detailed on line 1 of Exhibit A-28 (BSB-3). However, it is not anticipated that the O&M and Capital expenditures will change significantly after 2024. The Security Department intends to keep the staffing levels constant through 2025.

b. Please refer to Attachment U21490-AG-CE-0341-Myers_ATT_1 for the labor cost savings. Reduced headcount assumptions were factored into the calculation on benefits costs for the years 2024 and 2025. There were no costs savings for space associated with this initiative. Overhead loadings reflect the most recent rate available at the time of the rate case preparation.

c. Please refer to Attachment U21490-AG-CE-0341-Myers_ATT_1 for the exhibit and line number where the cost savings are included. Cost savings for Corporate Services were not included in any exhibit because the projected test year Corporate Services O&M costs were calculated using the historical test year actuals increased for inflation. Cost savings for Fleet were not included in any specific exhibit because they are allocated to various functional areas based on the units' defined work assignments as described in the direct testimony of Company witness Adam S. Carveth.

Witness: Heidi J. Myers
Date: April 11, 2024

Consumers Energy Company
Voluntary Separation Program FTE Reductions and O&M Cost Savings
U21490-AG-CE-0341-Myers_ATT_1

Department	FTEs	2023 ($000)	2024 ($000)	2025 ($000)	12-Months Ending 9/30/25 ($000)	Exhibit No.	Line No.	Note
Total Company	404	8.456	20.678	21.282				
Gas								
Gas Operations	30	0.264	0.615	0.615	0.615			
	16	0.172	0.403	0.403	0.403	A-103 (JPP-3, p1)	5, 6, 7, 9	Savings included in labor portion of indicated lines.
	14	0.092	0.212	0.212	0.212	A-104 (JPP-4, p1)	2	Savings included in labor portion of indicated lines.
Gas Engineering and Supply	48	0.341	1.027	1.027	1.027			
	32	0.244	0.708	0.708	0.708	A-95 (KAP-2)	2, 3, 4, 5, 6, 8, 9, 10,14	Savings included in labor portion of indicated lines.
	16	0.097	0.319	0.319	0.319	A-95 (KAP-2)	1, 12, 13	Savings included in labor portion of indicated lines.
Gas Compression & Storage	5	0.113	0.251	0.251	0.251	A-80 (TKJ-1, p3)	2-8	Savings included in labor portion of indicated lines.
Customer Operations	14	0.277	0.664	0.664	0.664	A-91 (SQM-2), page 1	1,2	Savings included in labor portion of indicated lines.
Sales Margin/Growth	7	0.084	0.213	0.255	0.244	A-92 (SQM-3) Confidential, page 1	1-Jan	Savings included in labor portion of indicated lines.
IT	13	0.373	0.894	0.894	0.894	A-17 (SHB-1), page 1	1	
Security	3	0.093	0.230	0.230	0.230	A-28 (BSB-3), page 1	1	See additional discussion in part a. of the response.
Corporate Services	26	1.216	3.136	3.136	3.136	Not included in any exhibit.		See additional discussion in part c. of the response.
Facilities	13	0.214	0.597	0.597	0.597	A-70 (QAG-2)	1, 2, 3	Savings included in labor portion of indicated lines.
Fleet	2	0.029	0.068	0.068	0.068	Not included in any exhibit.		See additional discussion in part c. of the response.
Employee Benefits	1	0.073	0.132	0.132	0.132	A-66 (KKG-1)	6	
	161	3.075	7.825	7.868	7.858			

Question:

113. Refer to lines 13-19 on page 19 of Mr. Griffin's direct testimony. Please provide the number of geohazard assessments completed for each year 2018 to 2023 and forecasted for 2024, 2025, the first 9 months of 2024, and the projected test year with the related dollars in Excel.

Response:

Year	# of Geohazard Assessments	Geohazard Assessment Charges
2018	0	Related charges are included in the overall project cost for the remediation. See attachment U-21490-AG-CE-0271-Griffin_ATT_1 for the for the total remediation cost by year.
2019	0	
2020	0	
2021	39	
2022	19	
2023	42	
2024	Will be identified by bend strain analysis	See Workpaper WP-MPG-15 for the 2024 total O&M remediation work costs which would include geohazard costs.
2025	Will be identified by bend strain analysis	See Workpaper WP-MPG-17 for the 2025 total O&M remediation work costs which would include geohazard costs.

Witness: MICHAEL P. GRIFFIN
Date: April 3, 2024

U-21490-AG-CE-271-Griffin_ATT_1		Pipeline Integrity Transmission Remediation O&M Expenses					
Project Definition		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
GC-90302	Pipeline Integrity - T&S	-	-	-	-	13,908	-
GL-00689	STC-600 Clrkstn Jct to Squirrel O-REM	1,703	2,080	-	-	-	-
GL-00974	JXN-PI Baseline Assessments	-	-	-	-	-	-
GL-01591	STC-26 Puttygut Mainline O-REM	-	-	-	5,966	-	-
GL-01596	FDM-400 Laingsburg to Fenton O-REM	-	(147,181)	-	-	-	-
GL-01617	FDM-2800 Freedom to Clawson O-REM	1,435	-	470	608	-	-
GL-01741	MAR-Processing Plant to Gillow L/R O-REM	-	-	-	-	-	10,468
GL-01742	KZO-White Pigeon to V Drive South O-REM	1,863	1,078,784	4,083	-	-	1,921
GL-01744	FDM-Chelsea to Fenton O-REM	-	-	-	2,072	-	-
GL-01745	NVL-Pontiac to Decker O-REM	15,000	(15,000)	-	-	-	-
GL-01746	KZO-Olmstead to Galesburg O-REM	-	20,905	-	-	-	-
GL-01747	KZO-Dorr to Middleville Caledonia O-REM	-	36	-	-	-	-
GL-01749	STC-Ira Mainline 20" O-REM	82,492	-	-	-	-	-
GL-01750	STC-Clarkston to Squirrel O-REM	281,217	3,939	-	194,502	994	-
GL-01751	NVL-Northville to Coolidge O-REM	1,401,569	92,677	(2,198)	-	-	-
GL-01752	STC-St. Clair to Mt. Clemens O-REM	124,962	35	-	-	-	-
GL-01754	SAG-Mt Pleasant to Zilwaukee O-REM	650	-	-	-	-	-
GL-01755	KZO-Schoolcraft to Plainwell O-REM	(17,762)	-	-	-	-	-
GL-01756	KZO-White Pigeon to Schoolcraft O-REM	135	-	-	-	-	-
GL-01757	KZO-Plainwell to 30th O-REM	-	64	-	-	-	-
GL-01759	SAG-Airport to Herrick O-REM	629,203	17,342	72,827	3,375	-	-
GL-01760	FDM-Maple Dale to Park Rd O-REM	-	6,841	-	-	-	-
GL-01762	SAG-M72 VS to Shell Processing O-REM	-	51,796	-	-	-	-
GL-02137	KZO-V Drive VS to Chelsea VS, M52 O-REM	4,814,352	(1,508,767)	-	-	-	2,776
GL-02138	KZO-Trunkline to WPCS O-REM	370,352	66,997	-	-	-	-
GL-02139	STC-STCS to Rchstr CG, Shldn Rd O-REM	430,521	7,712	4,830	-	-	-
GL-02140	RAY-RAYCS to Atlas VS O-REM	1,888,801	34,136	5,014	33,296	-	-
GL-02141	STC-Sqrl Rd VS to Pont CG Adams O-REM	501,169	270,795	29,169	-	-	-
GL-02142	SAG-Crpntr Rd VS to Flnt CG Brnch O-REM	1,846,790	191,404	-	33,562	-	452
GL-02143	SAG-Wilson Rd VS to Akron CG O-REM	256,093	63,370	2,110	-	-	-
GL-02144	STC-31 Mile Rd to Dutton Rd Int O-REM	1,060,477	2,375,568	20,721	-	207,545	-
GL-02146	STC-Plymth Sta to Coolidge CG O-REM	3,249,816	(6,980)	-	-	-	4,583
GL-02147	MAR-Riverside Mainline 12" O-REM	2,271,379	59,802	-	-	-	-
GL-02148	STC-Lenox Mainline O-REM	397,913	3,073	6,850	-	-	-
GL-02149	OVC-OVCS to Dorr CG 18th St O-REM	2,398,390	45,538	-	-	-	10,604
GL-02150	KZO-Clntonia Rd VS to Charlot CG O-REM	572,520	1,036	-	-	-	-
GL-02151	FDM-Fenton Int to Clrkstn O-REM	1,501,516	88,893	-	-	-	-
GL-02152	SAG-Crpntr Rd VS to Thetford VS O-REM	167,152	106,729	270	-	-	-
GL-02153	KZO-Lute Rd VS to HH CG Moscw Rd O-REM	1,135,287	92,067	-	-	(199)	-
GL-02441	MAR-MichconInt to GillowRd VS O-REM	-	-	1,236,898	(1,321)	1,138,634	13,386
GL-02443	MAR-MichconInt to M72 VS O-REM	-	12,358	-	-	-	-
GL-02444	MAR-2400B1 MichCon to M72 O-REM	-	1,110	261,424	(1,321)	-	-
GL-02445	STC-SquirelRd VS to RochstrRd VS O-REM	-	554,226	17,528	22	-	-
GL-02446	SAG-Ovid to Mt Pleasant O-REM	-	1,690,765	57,948	-	143,984	-
GL-02447	SAG-MRCS to ColemanBeaverton O-REM	-	962,525	1,645,345	28,435	4,609	79,990
GL-02448	NVL-ClarkstonInt to NVLCS O-REM	-	649,933	11,438	-	-	-
GL-02449	OVS-Salem Mainline Sta to Fld O-REM	-	1,078,315	78,291	7,104	(1,509)	(10,961)
GL-02450	OVS-Salem Mainline 2 Sta to Fld O-REM	-	16,438	51	-	-	-
GL-02464	JXN-Chelsea to Northville O-REM	-	2,020,295	26,112	63,142	11,572	-
GL-02465	JXN-FDMCS to Dansville VS O-REM	-	4,286,681	2,263,097	3,439	(38,733)	(10,186)
GL-02466	JXN-ClntniaRd VS to DwitStaTrnrRd O-REM	-	1,406,012	39,130	-	-	-
GL-02467	JXN-DwitStaTrnrRd to Lngsbrg CG O-REM	-	712,604	(7,092)	1,813	-	-
GL-02680	SAG-100A Dnsvl VS to Ovid VS O-REM	-	-	3,451,923	597,326	7,112	2,519
GL-02683	KZO-1300 Plnwl VS to Plmr St O-REM	-	-	34,237	679	-	-

U-21490-AG-CE-271-Griffin_ATT_1		Pipeline Integrity Transmission Remediation O&M Expenses					
Project Definition		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
GL-02684	MAR-Cranberry Lat 63W2 O-REM	-	-	478,488	(1,321)	-	6,847
GL-02685	MAR-Cranberry Lat 62W2 O-REM	-	-	634,881	(1,308)	-	9,675
GL-02755	SAG-100A Ovid to Mt Pleasant O-REM	-	-	2,149,735	81,445	106,692	13,618
GL-02761	MAR-Riverside Mainline O-REM	-	-	354,810	95,286	-	-
GL-02762	NVL-Lyon 34 O-REM	-	-	67,682	(1,321)	-	-
GL-02781	SAG-2800 Pipe Repl 116875-116920	-	-	-	61	-	-
GL-02866	OVS-1100 Midcal to Clntnia O-REM	-	-	-	1,132,092	8,845	7,984
GL-02904	SAG-1700 RAYCS to Red Run CG O-REM	-	-	-	53,772	1,641	-
GL-02905	SAG-500 Ovid VS to GrndBlnc O-REM	-	-	-	1,484,234	5,044	19,428
GL-02906	OVC-1300 OVCS to Plainwell VS O-REM	-	-	-	1,166,492	1,030,848	31,785
GL-02907	SAG-300 Midland CG to Zil CG O-REM	-	-	-	796,956	11,427	19,765
GL-02908	KZO-1300 Plainwell VS to Kzo CG O-REM	-	-	-	1,744,009	97,026	8,473
GL-02909	STC-2700 Kern Rd to Clrkstn Jct O-REM	-	-	-	76,282	2,291	-
GL-02910	KZO-1200B WPCS to Lutes VS O-REM	-	-	-	622,373	38,154	24,516
GL-02911	SAG-2100 Flint CG to Crpntr Rd VS O-REM	-	-	-	25,627	1,641	-
GL-02912	NVL-2300 NVLCS to Newbrg CG O-REM	-	-	-	30,622	130,315	-
GL-02913	SAG-100B Ovid VS to StLou JCT O-REM	-	-	-	3,212,976	50,000	48,111
GL-02914	SAG-100B StLou JCT to Herick VS O-REM	-	-	-	29,112	1,641	-
GL-02915	SAG-100B Lngsbrg Int to Ovid VS O-REM	-	-	-	1,798,290	3,987	47,004
GL-02916	STC-600 Clrkstn JCT to Squirel VS O-REM	-	-	-	44,324	140,747	2,074,091
GL-02917	STC-24W Ray Mainline O-REM	-	-	-	46,822	772,824	(325,341)
GL-02918	JXN-100A FDMCS to Dansville O-REM	-	-	-	945,871	3,177	6,889
GL-02919	JXN-100A Dansville to Ovid O-REM	-	-	-	1,908,885	15,916	21,576
GL-02938	MAR-Cranberry Lat 65E O-REM	-	-	260,476	(14,638)	-	-
GL-03074	SAG-1900 Atlas to GrndBlnc 0-REM	-	-	-	-	37,144	-
GL-03088	KZO-1200A Trnkline to WPCS O-REM	-	-	-	-	5,845	41,585
GL-03089	JXN-1200B MoscwRd to Chlsea VS O-REM	-	-	-	-	287,290	160
GL-03090	OVS-Salem 16in Mainline Seg 2 O-REM	-	-	-	-	117,522	728
GL-03091	SAG-300 ClmnBvrtn CG to Mdlnd CG O-REM	-	-	-	-	26,120	-
GL-03092	MAR-2400A GillowRd to MRCS O-REM	-	-	-	-	18,124	-
GL-03093	MAR-2400B GillowRd to MRCS O-REM	-	-	-	-	7,756	-
GL-03094	SAG-100A AirportRd VS to MRCS O-REM	-	-	-	-	2,619,567	1,278,690
GL-03095	NVL-1070 NVCS to ShldnRd CG O-REM	-	-	-	-	25,841	33,658
GL-03096	SAG-700 StLou VS to SagDutchRd CG O-REM	-	-	-	-	530,734	7,609
GL-03097	STC-2070 DutnRd Int to Cldge CG O-REM	-	-	-	-	22,416	37,188
GL-03098	JXN-400 Lngsbrg Int to Fentn Int O-REM	-	-	-	-	6,773,535	1,988,128
GL-03099	SAG-100A Ovid VS to MtPlsnt VS O-REM	-	-	-	-	137,772	1,570,646
GL-03176	JXN-State Wide Geohazard Assessmnt O&M	-	-	-	-	129,572	88,703
GL-03209	JXN-PL Integrity Matl Verification	-	-	-	-	9,939	34,049
GL-03235	MAR-L100B-36-1 Herrick Rd O-REM	-	-	-	-	2,795	79,040
GL-03236	STC-L1060-1 Dunham Rd O-REM	-	-	-	-	2,795	8,913
GL-03237	OVS-L1100-4 18th St O-REM	-	-	-	-	2,795	212,986
GL-03238	STC-L1500-2 Sheldon Rd O-REM	-	-	-	-	2,795	4,205
GL-03239	NVL-L1600-1 Coolidge Hwy O-REM	-	-	-	-	2,795	(597)
GL-03240	KZO-L1800-1B Hill Rd O-REM	-	-	-	-	97,396	98,114
GL-03241	KZO-L3010-1 Olmstead Rd O-REM	-	-	-	-	2,795	36,366
GL-03242	NVL-L2010-1 Squirrel Rd O-REM	-	-	-	-	2,795	76,947
GL-03243	NVL-L2020-1 Decker Rd O-REM	-	-	-	-	2,795	184,603
GL-03244	SAG-L250-1 Pickard Rd O-REM	-	-	-	-	2,795	336,744
GL-03245	FDM-L2800-1 Maple Rd O-REM	-	-	-	-	2,795	1,293,709
GL-03246	STC-Ira ML Swan Ck O-REM	-	-	-	-	2,795	(2,795)
GL-03247	STC-Pgut ML 26 O-REM	-	-	-	-	2,795	29,390
Overall Result		**25,384,994**	**16,394,951**	**13,206,547**	**16,249,638**	**14,790,243**	**9,558,741**

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Pipeline Integrity - Transmission Capital and O&M Projects - 2024

Pipeline Integrity Transmission - O&M 2024 Costs by Project ID

Work Item	Work Type	Inspection Tool	O&M Expense	O&M Inspection	O&M Remediation	MAOP Reconfirmation	O&M Material Verification	Number of Assessments / Studies
(10723) 100A-20-1B1 Freedom to Dansville	Inline Inspection & Remediation	Caliper, cMFL, U-aMFL, EMAT	$ 3,110,242	$ 630,242	$ 2,400,000		$ 80,000	
(10816) 100A-22-2A Airport Rd to Muskegon River CS	Inline Inspection & Remediation	EMAT	$ 1,285,156	$ 665,155	$ 600,000		$ 20,000	
(10817) DA - 100A-22-36-22 Mt Pleasant to Airport Rd	Direct Assessment	Direct Assessment	$ 150,000					
(10853) 2400A-2 Gillow Rd VS to Muskegon River VS	Inline Inspection & Remediation	Caliper, cMFL	$ 1,710,000	$ 180,000	$ 1,200,000	$300,000	$ 30,000	
(10856) 300-4 Coleman-Beaverton CG-Shaffer Rd to Midland	Inline Inspection & Remediation	Caliper, cMFL	$ 1,260,000	$ 180,000	$ 1,050,000		$ 30,000	
(10866) 1020-1 Northville CS to S. Lyon-Whitmore Lake	Inline Inspection	Caliper, cMFL	$ 180,000	$ 180,000				
(10867) 1060-1 Mt. Clemens CG to St. Clair CS	Inline Inspection & Remediation	Caliper, cMFL	$ 640,000	$ 180,000	$ 450,000		$ 10,000	
(10870) 1600-1 Northville CS to Coolidge CG-Coolidge Hwy	Inline Inspection & Remediation	Caliper, cMFL	$ 1,410,000	$ 180,000	$ 1,200,000		$ 30,000	
(10872) 1800-1B Schoolcraft to Plainwell	Inline Inspection & Remediation	Caliper, cMFL	$ 640,000	$ 180,000	$ 450,000		$ 10,000	
(10874) 2020-1 Pontiac Trail VS to Walled Lake CG-Decker Rd	Inline Inspection & Remediation	Caliper, cMFL	$ 330,000	$ 180,000	$ 150,000			
(10876) 1200A-2 White Pigeon to V Drive	Inline Inspection & Remediation	Caliper, cMFL	$ 1,080,000	$ 180,000	$ 860,000		$ 40,000	
(10877) 2500-1 Processing Plant VS to M72 VS	Inline Inspection & Remediation	Caliper, cMFL	$ 640,000	$ 180,000	$ 450,000		$ 10,000	
(10912) 3200-1 Vector/Leslie INT-Jackson Rd to Kinder Morgan VS-Chapin ST	Inline Inspection & Remediation	Caliper, cMFL	$ 490,000	$ 180,000	$ 300,000		$ 10,000	
(10914) I-ML St. Clair CS to Ira Storage VS-SwanCreek Rd	Inline Inspection & Remediation	Caliper, cMFL	$ 330,000	$ 180,000	$ 150,000			
(10924) 1200A-3 "V" Drive VS to Chelsea VS-M52 Hwy	Inline Inspection & Remediation	Caliper, cMFL	$ 810,000	$ 180,000	$ 600,000		$ 30,000	
(10928) 1500-2 St. Clair CS to Rochester CG-Sheldon Rd	Inline Inspection	Caliper, cMFL	$ 180,000	$ 180,000				
(10929) 1900-2 Ray CS to Flint CG-Irish Rd aka Atlas VS	Inline Inspection	Caliper, aMFL	$ 180,000	$ 180,000				
(10931) 2060-1 Carpenter Rd VS to Flint CG-Branch Rd	Inline Inspection	Caliper, cMFL	$ 180,000	$ 180,000				
(10933) 2100-4 Wilson Rd VS to Akron CG-Akron Rd, TRS 095830	Inline Inspection	Caliper, aMFL	$ 180,000	$ 180,000				
(10935) 2200-1 Chelsea VS-M52 Hwy to Fenton INT-Mabley Hill Rd	Inline Inspection & Remediation	Caliper, cMFL	$ 490,000	$ 180,000	$ 300,000		$ 10,000	
(10936) 2700-1 31 Mile Rd VS to Dutton Rd INT	Inline Inspection	Caliper, aMFL	$ 330,000	$ 180,000		$150,000		
(10939) L-ML St. Clair CS to Lenox Meter Station (Lenox ML)	Inline Inspection	Caliper, cMFL	$ 180,000					
(10998) DA - Ray Compressor Station	Direct Assessment		$ 600,000					
(11257) DA - Farmington Hills CG	Direct Assessment		$ 150,000					
(11258) DA - Greenfield CG	Direct Assessment		$ 150,000					
(11261) DA - Middleville-Caledonia CG	Direct Assessment		$ 150,000					
(11263) DA - Dutton Rd INT	Direct Assessment		$ 150,000					
(11265) DA - Segment 3020-1	Direct Assessment		$ 150,000					
(11266) DA - Olmstead Rd VS	Direct Assessment		$ 150,000					
(11267) DA - Pontiac Tr VS	Direct Assessment		$ 150,000					
(11268) DA - Squirrel Rd VS	Direct Assessment		$ 150,000					
(11275) DA - White Pigeon CS	Direct Assessment		$ 600,000					
(12104) W-ML-24in Winterfield 24" Mainline	Inline Inspection	Caliper, aMFL	$ 180,000	$ 180,000				
(12208) OneBridge Software Support	Software Support		$ 200,000					
(13672) 1060-1 - Replace Launcher Equalizing Line	Construction		$ 200,000					
(2283) Fitness for Purpose Reports - EMAT Projects	Studies and Support		$ 45,000					2
(2284) Bending Strain & Pipe Movement Studies	Studies and Support		$ 735,000					
(2287) LSC GIS Portal Software Support	Software Support		$ 350,000					
(2288) SCC DA Assessments	SCCDA		$ 900,000					3
(8892) Transmission Pipeline Cleaning Program	Transmission Cleaning for Inspection		$ 1,200,000					6
(9040) Fatigue Crack Growth Review - Pressure Cycling	Studies and Support		$ 280,000					8
TOTAL EXPENSE			**$ 22,275,398**	**$ 4,715,397**	**$ 10,160,000**	**$450,000**	**$ 310,000**	**19**

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Pipeline Integrity - Transmission Capital and O&M Projects - 2025

Pipeline Integrity Transmission - O&M 2025 Costs by Project ID

Work Item	Work Type	O&M Expense	O&M Inspection	O&M Remediation	MAOP Reconfirmation	O&M Material Verification	Number of Assessments / Studies
(10815) 100A-22-1A Ovid VS to Mt. Pleasant	Inline Inspection & Remediation	$ 3,241,801	$ 933,371	$ 2,248,430		$ 60,000	
(10854) 2400B-2 Gillow Rd Valve Site to Muskegon River CS	Inline Inspection & Remediation	$ 1,410,000	$ 180,000	$ 1,200,000		$ 30,000	
(10862) 700-1 St. Louis to Saginaw	Inline Inspection & Remediation	$ 2,640,000	$ 180,000	$ 2,100,000	$ 300,000	$ 60,000	
(10866) 1020-1 Northville CS to S. Lyon-Whitmore Lake	Remediation	$ 310,000	$ -	$ 300,000		$ 10,000	
(10928) 1500-2 St. Clair CS to Rochester CG-Sheldon Rd	Remediation	$ 310,000	$ -	$ 300,000		$ 10,000	
(10929) 1900-2 Ray CS to Flint CG-Irish Rd aka Atlas VS	Remediation	$ 1,230,000	$ -	$ 1,050,000	$ 150,000	$ 30,000	
(10931) 2060-1 Carpenter Rd VS to Flint CG-Branch Rd	Remediation	$ 460,000	$ -	$ 450,000		$ 10,000	
(10933) 2100-4 Wilson Rd VS to Akron CG-Akron Rd, TRS 095830	Remediation	$ 150,000	$ 150,000				
(10936) 2700-1 31 Mile Rd VS to Dutton Rd INT	Remediation	$ 610,000	$ -	$ 450,000	$ 150,000	$ 10,000	
(10939) L-ML St. Clair CS to Lenox Meter Station (Lenox ML)	Remediation	$ 770,000	$ -	$ 750,000		$ 20,000	
(10952) 1100-6A Clintonia Rd VS to Dewitt Sta-Turner Rd	Inline Inspection	$ 180,000	$ 180,000	$ -		$ -	
(10953) 1100-6C Dewitt Sta-Turner Rd to Laingsburg CG-Round Lake Rd	Inline Inspection	$ 180,000	$ 180,000	$ -		$ -	
(10954) 1200A-4 Chelsea VS-M52 Hwy to Northville CS	Inline Inspection	$ 180,000	$ 180,000	$ -		$ -	
(10955) 1400-1 Northville CS to Clarkston JCT & INT-Fish Lake Rd	Inline Inspection	$ 180,000	$ 180,000	$ -		$ -	
(10956) 300-1 Muskegon River CS to Coleman-Beaverton CG-Shaffer Rd	Inline Inspection & Remediation	$ 1,260,000	$ 180,000	$ 1,050,000		$ 30,000	
(10957) 400-3 Fenton INT-Mabley Hill Rd to Rose Center CG-Fish Lake Rd	Inline Inspection	$ 180,000	$ 180,000	$ -		$ -	
(10959) 600-3 Squirrel Rd VS to Rochester VS-Sheldon Rd	Inline Inspection & Remediation	$ 1,760,000	$ 680,000	$ 1,050,000		$ 30,000	
(10960) R-ML-24-E Ray (East Header) CS to TRS 046301	Inline Inspection	$ 180,000	$ 180,000	$ -		$ -	
(10961) S-ML-1-16 Salem Mainline (Segment 1)	Inline Inspection	$ 180,000	$ 180,000	$ -		$ -	
(11230) DA - Holly CG - Grange Hall Rd	Direct Assessment	$ 150,000					
(11233) DA - Mt Clemens CG	Direct Assessment	$ 150,000					
(11234) DA - Novi-Wixom CG	Direct Assessment	$ 150,000					
(11271) DA - Jackson CG - Hart Rd	Direct Assessment	$ 150,000					
(11272) DA - Kalamazoo CG - M Ave	Direct Assessment	$ 150,000					
(11273) DA - Laingsburg Int_CG Round Lake	Direct Assessment	$ 150,000					
(11274) DA - Sheldon Rd CG	Direct Assessment	$ 150,000					
(11276) DA - Segment 1030-1	Direct Assessment	$ 150,000					
(11277) DA - Segment 4010-2	Direct Assessment	$ 150,000					
(11278) DA - Kinder Morgan VS - Chapin St	Direct Assessment	$ 150,000					
(12104) W-ML-24in Winterfield 24" Mainline	Remediation	$ 460,000	$ -	$ 450,000		$ 10,000	
(12125) 100C-16-1 Airport Rd VS to Herrick Rd VS	Inline Inspection & Remediation	$ 1,600,000	$ 680,000	$ 900,000		$ 20,000	
(12208) OneBridge Software Support	Software Support	$ 200,000					
(12209) GeoHazard Study for Risk	Studies and Support	$ 250,000					1
(12848) R-ML-N Ray Mainline North - 16"	Inline Inspection & Remediation	$ 790,000	$ 180,000	$ 450,000	$ 150,000	$ 10,000	
(2283) Fitness for Purpose Reports - EMAT Projects	Studies and Support	$ 135,000					3
(2284) Bending Strain & Pipe Movement Studies	Studies and Support	$ 565,000					15
(2287) LSC GIS Portal Software Support	Software Support	$ 350,000					
(2288) SCC DA Assessments	SCCDA	$ 300,000					1
(8892) Transmission Pipeline Cleaning Program	Transmission Cleaning for Inspection	$ 1,000,000					5
(9040) Fatigue Crack Growth Review - Pressure Cycling	Studies and Support	$ 140,000					4
TOTAL EXPENSE		**$ 22,701,801**	**$ 4,423,371**	**$ 12,748,430**	**$ 750,000**	**$ 340,000**	**29**

Question:

235. Refer to Exhibit A-19, page 1. Please expand this schedule with actual expenses for 2021 and 2023 and provide in Excel.

Response:

Please refer to attachment U21490-AG_CE-0394_Baker_ATT_1 for the expanded Investments O&M expense schedule to include 2021 and 2023 actuals in Excel.

Witness: Stacy H. Baker
Date: April 9, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Information Technology Investments O&M Expenses
For the Years 2021, 2022, 2023, 2024, Test Year 12 Months Ending September 30, 2025, and 2025
($000)

AttachmenT: U21490-AG-CE-0394_ATT_1
Witness: SHBaker
Date: April 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Actuals			Projected				
Line No.	Description	12 Months Ended 12/31/2021	12 Months Ended 12/31/2022	12 Months Ended 12/31/2023	12 Months Ending 12/31/2024	3 Months Ending 12/31/2024	9 Months Ending 9/30/2025	12 Months Test Year	12 Months Ending 12/31/2025
1	**Investments Planning**	**$ 716**	**$ 478**	**$ 431**	**$ 343**	**$ 86**	**$ 257**	**$ 343**	**$ 343**
	Labor	362	325	313	343	86	257	343	343
3	Material	-	0	0	0	0	0	0	0
4	Contracts	353	153	118	0	0	0	0	0
5	Business Expense	0	0	0	0	0	0	0	0
6	**Investments O&M**	**$ 6,876**	**$ 6,391**	**$ 3,944**	**$ 6,854**	**$ 1,713**	**$ 4,582**	**$ 6,296**	**$ 6,110**
7	Labor	1,309	1,232	1,136	4,375	1,094	2,904	3,998	3,872
8	Software	357	434	451	792	198	423	621	564
9	Material	338	136	129	322	80	133	213	177
10	Contractor Costs	4,505	3,920	2,041	807	202	827	1,029	1,103
11	Overheads & Others	368	668	186	557	139	296	435	395
12	**Total Investments Expense**	**$ 7,592**	**$ 6,869**	**$ 4,375**	**$ 7,197**	**$ 1,799**	**$ 4,840**	**$ 6,639**	**$ 6,453**

Computation of Revenue Deficiency for Projected Test Year Ending September 2025

($000)

Line	Description	Company Filed Amount	AG Recommended Adjustments	Revised Amount
	(a)	(b)	(c)	(d)
1	Rate Base [(1)]	$ 10,970,344	$ (385,346)	$10,584,998
2	Rate of Return	6.20%	-0.24%	5.96%
3	Income Required	$ 680,004	$ (49,138)	$ 630,866
4	Adjusted Net Operating Income [(2)]	578,341	48,583	626,924
5	Income Deficiency (Sufficiency)	$ 101,663	$ (97,721)	$ 3,942
6	Revenue Multiplier	1.3381	1.3381	1.3381
7	**Revenue Deficiency (Sufficiency)**	**$ 136,034**	**$ (130,760)**	**$ 5,274**

(1) Rate Base Adjustments Exhibit AG-39.

(2) AG adjustments to Operating Income

			Source
Revenue		$ 20,980	Exhibit AG-59
Lower Forecast of O&M Expenses		35,300	Exhibit AG-60
Property Taxes		2,839	Exhibit AG-39
Depreciation Expense		8,186	Exhibit AG-39
Total		$ 67,305	
Effective Tax Rate (1-1/1.3381)	25.27%		
Taxes		17,006	
Interest Synchronization for cap. Ex. adjustments		(1,716)	AG-71 WP1
Adjusted Net Operating Income		$ 48,583	

Question:

30. Refer to the direct testimony of Ms. Conrad and Mr. Stuart on incentive compensation. Please provide the following information:

a. The number of operating goals that need to be achieved to trigger a payout under the incentive compensation plan for officers and nonofficer employees.

b. Provide a schedule in Excel showing the number of safety incidents in 2019 2020, 2021, 2022 and 2023.

c. Provide the amount of incentive compensation expense that would be incurred in the projected test year based only on achieving threshold level of performance for non-financial measures.

d. Provide the amount of incentive compensation expense that would be incurred in the projected test year based only on achieving target level of performance for non-financial measures.

e. Provide a schedule detailing the percent payout to officer and nonofficer employees for each of the plan years 2014 to 2023.

f. For each of the plan years 2014 to 2023 provide a schedule in Excel detailing which incentive plan performance measures were below threshold and which measures were between threshold and the target performance level and which measures were above target.

g. For each of the plan years 2014 to 2023, what percentage of the incentive plan measures were required to meet the threshold level to achieve a payout under the plan.

h. State how often and by what means employees are kept abreast of the periodic standings for the ICP metrics for Employee Safety, Employee Empowerment, and Customer Experience.

Response:

a. Beginning in 2022, a specific number of operational measures do not need to be met for a payout to be achieved. There is no minimum number of measures to achieve payment. Absolute goal achievement was removed in 2022 and changed to banded goal achievement. Banded goals set minimums (thresholds), targets, and maximum payout for each individual goal or measure. This allows for payout for levels below target at less than 100% and above target at greater than 100%. See Exhibit A-40 (AMC-1).

b. See response from R. Michael Stuart.

c. The amount of incentive compensation expense that would be incurred in the projected test year based only on achieving threshold level of performance for non-financial measures is $754,000.

d. The amount of incentive compensation expense that would be incurred in the projected test year based only on achieving target level of performance for non-financial measures is $1,508,000.

e. See U21490-AG-CE-Conrad_ATT_1 for schedule detailing the percent payout to officer and nonofficer employees for the plan years 2014 to 2017 and see U21490-AG-CE-Conrad_ATT_2 for the plan years 2018 to 2023.

f. For a schedule detailing which incentive plan performance measures were below threshold and which measures were between threshold and the target performance level and which measures were above target see U21490-AG-CE-Conrad Attachment 1 for years 2014 – 2017 and U21490-AG-CE-Conrad Attachment 2 for the plan years 2018 to 2023.

g. For a schedule detailing what percentage of the incentive plan measures were required to meet the threshold level to achieve a payout under the plan see U21490-AG-CE-Conrad Attachment 1 for years 2014 – 2017 and U21490-AG-CE-Conrad Attachment 2 for the plan years 2018 to 2023.

h. See response from R. Michael Stuart.

Witness: Amy M. Conrad
Date: March 12, 2024

U21308-AG-CE-0457
Page **1** of **1**

Question:

250. Refer to page 36 of Mr. Hale's direct testimony. For the ASP, please:

a. Provide the revenue, costs in detail, and margin for each year 2017 to 2022 actual and forecasted for 2022, 2023, 2024, and projected test year in Excel.

b. Provide the basis and calculations supporting the forecasted amounts for each period in subpart (a) to this question in Excel with formulas intact.

c. Provide the number of customers in the ASP for each year 2017 to 2022 actual and forecasted for 2022, 2023, 2024, and the projected test year in Excel.

d. Explain any forecasted increases in expense in each year and identify the specific reasons with related dollar amount and provide the basis for the expected increase.

Response:

a. Please see u21308-AG-CE-0457-Hale_ATT_1, the Home Energy Products tab for the requested data.
b. See U21308-AG-CE-0457-Hale_ATT_1.
c. See U21308-AG-CE-0457-Hale_ATT_1, the Contracts per Year tab.
d. Forecasted amounts include current customer contracts (includes contracts in and contracts out), a market forecast for contract growth schedule (an in-house forecast for market recruitment opportunity), anticipated revenues from contracts, expenses associated with forecasted contracts, internal labor and materials, and any overhead.
    a. 2023 expenses increased by $3.9m, primarily due to increased costs for materials and external resources. These costs are higher due to economical shifts and the growth of customer contracts.
    b. 2024 expenses increased by $1.845, primarily due to increased costs for contractor expenses and anticipated non-labor loadings. This is partially offset by reductions in internal labor leading to reduced overheads.
    c. Forecasted revenue for 2023 and 2024 meets or exceeds the forecasted expense growth, increasing by $5.282m and $1.845m respectively.

Witness: Cullen M. Hale
Date: March 17, 2023

Consumers Energy Company
Home Products Revenue and Expenses
For The Years Ended December 31, 2017 Through Test Year

Description	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024	Test Year
Revenue									
Home Products	$ 70,066	$ 72,898	$ 74,194	$ 78,954	$ 67,496	$ 67,761	$ 73,043	$ 74,888	$ 74,255
Revenue	$ 70,066	$ 72,898	$ 74,194	$ 78,954	$ 67,496	$ 67,761	$ 73,043	$ 74,888	$ 74,255
Expenses:									
Labor	$ 9,825	$ 9,969	$ 10,372	$ 9,451	$ 9,818	$ 11,957	$ 11,016	$ 9,236	$ 9,180
Material	$ 2,767	$ 358	$ 289	$ 2,770	$ 2,020	$ 1,968	$ 3,148	$ 3,151	$ 3,150
Contractor	$ 17,329	$ 17,124	$ 18,837	$ 28,173	$ 27,819	$ 28,522	$ 31,930	$ 34,723	$ 34,770
Non-Labor Overheads				$ -	$ 1,531	$ 4,932	$ 4,478	$ 3,519	$ 3,498
Non-Labor Other	$ 10,144	$ 20,730	$ 21,749	$ 8,887	$ 6,172	$ 6,064	$ 6,771	$ 8,560	$ 8,555
	$ 40,065	$ 48,181	$ 51,247	$ 49,281	$ 47,360	$ 53,443	$ 57,343	$ 59,188	$ 59,153
Margin	30,002	24,717	22,947	29,673	20,136	14,319	15,700	15,700	15,102

PROOF OF SERVICE - U-21490

The undersigned certifies that a copy of the ***Attorney General's Testimony and Exhibits of Sebastian Coppola*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 22nd day of April 2024.

Celeste R. Gill Digitally signed by Celeste R. Gill Date: 2024.04.22 15:06:29 -04'00'

Celeste R. Gill

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