Consumers Energy
Count on Us

December 16, 2024

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-21806 – In the matter of the application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find **Consumers Energy Company's Application, a Proposed Notice of Hearing, non-modifiable Protective Order, and the Testimony and Exhibits of Consumers Energy Company's Witnesses**. Also included is a Proof of Service showing service upon the parties in Consumers Energy Company's last two gas rate cases (Case Nos. U-21490 and U-21308). This is a paperless filing and is therefore being filed only in PDF.

Confidential materials of Company witnesses Stacy H. Baker, Jessica R. Byrom, Kendra K. Grob, and Heidi J. Myers are being filed under seal with the Michigan Public Service Commission.

In accordance with filing procedures adopted by the Michigan Public Service Commission in Case No. U-18238: (i) exhibits that were prepared in Microsoft Excel format are being filed in Excel with formulas intact in addition to PDF; (ii) tariff changes are being filed in Microsoft Word in addition to PDF with changes shown in redline format; and (iii) workpapers and economic models used to support the rate increase request will be provided to parties upon request in Microsoft Excel with formulas intact. Also provided to the Michigan Public Service Commission is Consumers Energy Company's Part II – Financial Information materials in the above docket via a secure link.

Digital copies of the public rate case filing, including native and PDF testimony, exhibits, workpapers, and models of Consumers Energy Company's witnesses, and Consumers Energy Company's Part II – Financial Information and Part III – Supplemental Data materials are being provided to the MPSC Staff and parties to Case Nos. U-21490 and U-21308 concurrently with this filing via a secure link and this link will be made available to any parties to Case No. U-21806 who were not previously served.

Sincerely,

Anne M. Uitvlugt
Phone: 517-788-2112
Email: anne.uitvlugt@cmsenergy.com

cc: Mike Byrne, Executive Director, MPSC Staff
David Chislea, MPSC Staff
Bill Stosik, MPSC Staff
Nick Revere, MPSC Staff
Bob Nichols, MPSC Staff
Parties to Case Nos. U-21490 and U-21308

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 for other relief.	)))))	Case No. U-21806

APPLICATION

Consumers Energy Company ("Consumers Energy" or the "Company") respectfully requests that the Michigan Public Service Commission ("MPSC" or the "Commission") authorize the Company to increase its rates for the distribution of natural gas and grant it additional relief as set forth herein. In support of its request, Consumers Energy states as follows:

I. INTRODUCTION

1. Consumers Energy is, among other things, engaged as a public utility in the business of purchasing, storing, transporting, distributing, and selling natural gas to approximately 1.8 million customers in the state of Michigan. The natural gas system of Consumers Energy is an integrated and interconnected system and is operated as a single utility system in which the same rates and tariffs are applicable.

2. Consumers Energy's retail natural gas business, including its retail transportation, storage, and distribution business, is subject to the jurisdiction of the Commission pursuant to various statutory provisions of 1909 PA 300, as amended, MCL 462.2 *et seq.*; 1919 PA 419, as amended, MCL 460.54 *et seq.*; 1939 PA 3, as amended, MCL 460.1 *et seq.*; and 1982 PA 304, as amended, MCL 460.6h(1) *et seq*. Pursuant to these statutory provisions, the Commission has the power and jurisdiction to regulate Consumers Energy's retail natural gas sales, transportation, storage, and distribution rates.

3. On July 23, 2024, in Case No. U-21490, the Commission issued an Order Approving Settlement Agreement which approved Consumers Energy's current retail natural gas transportation, storage, and distribution rates. Consumers Energy recovers its cost of gas associated with sales to its retail natural gas sales customers by means of a gas cost recovery clause authorized by the Commission pursuant to the provisions of 1982 PA 304, MCL 460.6h. In addition, the Commission has authorized, through various orders, the recovery of certain additional costs as set forth in the tariffs on file with the Commission.

II. <u>REQUESTED RATE INCREASE</u>

4. For purposes of this case, Consumers Energy has undertaken a complete examination, using a projected test year for the 12-month period ending October 31, 2026, of relevant items of investment, expense, and revenues for the determination of just and reasonable natural gas rates. The Company has chosen to utilize this projected test year as it will allow the rates established in this case to more closely reflect the investments made and expenses incurred during the time the rates established in this case will be in effect. Through its examination, Consumers Energy has determined that an increase in its natural gas rates is required to afford the Company a reasonable opportunity to recover its reasonable costs of providing natural gas service, including a reasonable return on common equity, as more fully described in the accompanying direct testimony and exhibits. Consumers Energy has calculated that, without rate relief, it will experience an annual jurisdictional revenue deficiency of approximately $248 million for the 12-month period ending October 31, 2026.

5. There are several factors contributing to Consumers Energy's need for additional gas revenues above levels currently recovered in base rates. These factors include:

(i.) Ongoing investments in the gas utility assets to provide safe, clean, reliable, and efficient service, and to comply with environmental and legal requirements;

(ii.) Ongoing investments in enhanced technology to provide improved operational efficiencies and increased customer satisfaction; and

(iii.) The Operation and Maintenance ("O&M") expenses necessary to, among other things, support long-term investments and improve customer interactions.

The net impacts of these and other factors described in more detail in the supporting direct testimony and exhibits, when examined in total, necessitate an increase in Consumers Energy's retail natural gas rates.

6. The rate relief requested in this filing is driven by the need to serve Consumers Energy's customers and reflects the Company's continued investment in Michigan. Consumers Energy is committed to customer value and system safety. Consumers Energy's ongoing investment in its transmission system, compression and storage system, and distribution system are part of Consumers Energy's capital investment plan to maintain and improve utility infrastructure, enhance safety of aging distribution assets, and ensure continued customer safety and a reliable system so that customers receive the service and value that they expect from the Company.

7. In order to provide an overview of the Company's long-term investments needed for the supply and delivery of natural gas, the Company is presenting the newest version of its Natural Gas Delivery Plan. The Natural Gas Delivery Plan provides a clear and transparent framework for the next decade of investments in the Company's natural gas assets, planning for natural gas supply and demand, continuing to evolve how the Company operates in accordance

with the Gas Pipeline industry standard American Petroleum Institute Recommended Practice 1173, and developing a strategic framework in response to the decarbonization goals of the Company's natural gas customers and future carbon policy relevant to the utility.

8. The Natural Gas Delivery Plan is built around four objectives: providing customers with safe, reliable, affordable, and more clean natural gas service. The principal factor necessitating rate relief is Consumers Energy's ongoing infrastructure investments in its Michigan natural gas utility system, which will enable it to execute its Natural Gas Delivery Plan. Examples of the investments being made are in the Company's Enhanced Infrastructure Replacement Program, Material Conditions Program, Compression and Storage Program, Well Rehabilitation Program, Regulatory Compliance Programs, and Capacity/Deliverability Programs. These continued investments in natural gas infrastructure reflect the Company's commitment to identify and replace at-risk natural gas distribution pipe across the state, and include investments required to maintain compliance with pipeline integrity requirements, transmission, compression, and storage system upgrades to better serve customers, and distribution system improvements. These investments will help ensure that the Company is able to deliver natural gas safely and reliably to customers.

Enhanced technology investments are also ongoing at the Company. Continually improving on customer service and internal operations will require significant Information Technology upgrades. An example of a technology upgrade project being undertaken is the SAP S/4HANA Implementation Project ("SAP Project"). This project will modernize the Company's current Enterprise Resource Planning SAP solution that will reach the end of mainstream vendor maintenance on December 31, 2027. Additionally, the Company's investments and O&M spending addresses the new digital capabilities and foundational technology required to realize the outcomes of the Natural Gas Delivery Plan, as well as those that enable residential and business programs that engage customers and adapt with their needs and behaviors. Without these new digital capabilities, the Company will be limited in its ability to achieve key outcomes of these plans, including: the ability to provide customers with the data, technology, and tools needed to interact with the Company; improvements in system monitoring via high resolution system visibility; and investments in risk modeling and predictive technologies to help avoid reactive events on the Company's system.

9. The Company strives to keep O&M costs at a reasonable level. Contributors to the Company's O&M expense include the effects of inflation, upgrades to the Company's system, and the Company's Natural Gas Delivery Plan. As the Company continues to invest in its technology assets, utilize cloud solutions, and increase cyber security requirements, O&M expenses are necessary to operate, support, secure, and maintain the technology systems in place. In addition, the Company is requesting rate recovery for a portion of incentive compensation costs that the Company incurs to attract and retain a talented workforce. Increases in revenue requirements have been offset, in part, by Company efforts to control O&M expenses and mitigate cost increases. Specifics regarding the Company's requests are described in the direct testimony and exhibits which are being filed in support of this Application.

10. In order to carry out its operational and customer-related goals, it is important that the financial health of Consumers Energy be sufficient to maintain adequate service quality and reliability, and to ensure the ability of the utility to access capital markets at reasonable terms so needed investments can be made. The investments that Consumers Energy plans to make in the next five years are not only necessary to provide safe, reliable natural gas utility service; they also will create other economic benefits, including Michigan jobs and tax base. To maintain its

financial health and support these investments, Consumers Energy requests that rates be established in this case based on an authorized return on common equity of 10.25% and reflect an overall rate of return on total rate base of 6.22% on an after-tax basis. The Company also requests that the Commission recognize for ratemaking purposes that the Company needs an equity ratio of 50.75%. Consumers Energy submits that the requested returns reasonably balance the interests of customers and investors.

11. Without a rate increase, Consumers Energy's gas revenues and overall rate of return will be below a just and reasonable level. Without rate relief, Consumers Energy's retail natural gas rates will be so low as to deprive Consumers Energy of a reasonable return on the Company's property and to amount to confiscation and deprivation of the Company's property, contrary to the Company's rights under the Constitutions of the United States and the State of Michigan.

III. RATE DESIGN, TARIFF, AND OTHER PROPOSALS

12. Consumers Energy is proposing use of a cost-based rate design by customer class. The Company proposes to allocate the required gas revenue increase among rate classes as set forth on Attachment A to this Application. A comparison of present and proposed rates is set forth on Attachment B to this Application.

13. Consistent with the Cost-of-Service Study ("COSS") methodologies approved by the Commission in prior cases, the Commission's rate case filing requirements established in Case No. U-18238, and the terms of the settlement agreement in Case No. U-21490, Consumers Energy is sponsoring two primary versions of the COSS (Version I and II) and an additional COSS (replaces the Average & Peak method with Average & Excess method). Consumers Energy supports the use of COSS Version II. These COSS are discussed in testimony which is being filed

in support of this Application. The Company has designed rates based on COSS Version II so that the revenue recovered from each customer class reflects the costs for that customer class. The Company is not proposing any significant changes to its rate design. A change is being proposed to its Transmission Only Transportation Service Rate. Under the Transmission Only Transportation Rate, the Company is proposing to offer four rate options (STT, LTT, XLTT, XXLTT) that consist of both a Customer Charge and a volumetric Transmission Charge.

14. In addition to seeking authority to increase the level of rates and charges, Consumers Energy is proposing various revisions to its gas rules, regulations, and tariffs. Reference to Consumers Energy's direct testimony and exhibits provides additional details on the relief being sought.

15. Consumers Energy is requesting the continuation of a Defined Benefit ("DB") Pension/Other Post-Employment Benefits ("OPEB") Volatility Mechanism. DB Pension and OPEB expenses are sensitive to changes in asset returns or other assumptions which creates significant potential for large variability in future expenses. Customers will continue to benefit from a mechanism that eliminates the risk of future volatility in expense. This mechanism would continue allowing the Company to defer annually the difference between the DB Pension/OPEB expense included in rates versus the actual annual DB Pension/OPEB expense recorded by the Company. If the Company's actual annual DB Pension/OPEB expense is less than the expense approved in rates, this difference would be recognized as a regulatory liability and be amortized over 10 years. Similarly, if actual annual DB Pension/OPEB expense is greater than the expense approved in rates, the Company proposes that this difference would continue to be recognized as a regulatory asset and be amortized in the same manner. Any amortization of these regulatory assets or liabilities would be included in future general rate cases. Further details supporting the

Company's proposal regarding the mechanism are described in the direct testimony and exhibits which are being filed in support of this Application.

16. In addition to other relief described in this Application, Consumers Energy is seeking Commission approval of certain accounting requests. The Company requests accounting approval for use of regulatory assets or regulatory liabilities, as needed, for the DB Pension/OPEB Volatility Mechanism. The Company is also requesting approval of certain cost deferrals associated with operation costs. First, the Company anticipates that the Pipeline and Hazardous Materials Safety Administration ("PHMSA") will adopt proposed regulatory amendments that will implement congressional mandates in the *Protecting the Infrastructure of Pipelines and Enhancing Safety Act of 2020* ("PIPES ACT") during the test year. Due to the current compliance timeline of the proposed rules, the Company is proposing the ability to defer any test year O&M expense that occurs as a result of the requirements of the final rules that are above the Company's requested funding level in this case. Next, the Company is requesting to defer for refund or recovery any O&M expenses related to its Staking and Locating Program that are below, or above, amounts included in rates for the test year. Lastly, Consumers Energy is requesting to defer the associated O&M expense for the SAP project and amortize it over 15 years consistent with the life of the assets.

17. Public Act 341 of 2016, MCL 460.6a(5), specifies a 10-month timeframe for processing rate cases. In Case No. U-18238, the Commission established new standard rate case

filing forms and instructions based on the 10-month statutory rate case processing timeframe. As directed, the Company has provided the information related to these requirements.

IV. TESTIMONY, EXHIBITS, AND RESERVATION OF RIGHT TO AMEND

18. Concurrently with the filing of this Application, Consumers Energy is filing written direct testimony and exhibits in support of natural gas rate relief and the other relief it is seeking in this case. Reference to this material will provide additional details regarding the proposals and relief being sought. The relief described in the direct testimony and exhibits should be considered as if specifically requested in this Application. Consumers Energy reserves the right to revise, amend, or otherwise change the relief it is requesting in any way appropriate depending upon the duration and progress of hearings in this proceeding, the issuance of orders that have an impact upon this case, or the occurrence of other material events.

19. In addition to the issues described above, it is possible that other pending or to-be-filed proceedings or other events may have impacts upon the rate adjustments requested in this filing. These impacts will be evaluated for materiality and may need to be considered in the results of this proceeding.

V. REQUEST FOR RELIEF

WHEREFORE, Consumers Energy Company respectfully requests that the Michigan Public Service Commission:

A. Authorize Consumers Energy to adjust its retail natural gas rates so as to provide additional revenue of approximately $248 million annually above the level established in Case No. U-21490 based on a projected 12-month test year ending October 31, 2026;

B. Authorize Consumers Energy to adjust its existing retail natural gas rates so as to produce a rate of return on common equity of not less than 10.25%;

C. Approve the DB Pension/OPEB Volatility Mechanism proposed by the Company in this case;

D. Grant the accounting authorizations described in the accompanying direct testimony;

E. Approve the modifications to the rates, rules, and regulations as described in the direct testimony and exhibits that accompany this Application; and

F. Grant Consumers Energy such other and further relief as is just and reasonable.

Respectfully submitted,
CONSUMERS ENERGY COMPANY

Dated: December 16, 2024

By: Kelly M. Hall

Kelly M. Hall
Deputy General Counsel and Vice
President, Rates and Regulation

Anne Uitvlugt

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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 for other relief.	)))))	Case No. U-21806

VERIFICATION

Kelly M. Hall states that she is Deputy General Counsel and Vice President, Rates and Regulation of Consumers Energy Company; that she has executed the foregoing Application for and on behalf of Consumers Energy Company; that she has read the foregoing Application and is familiar with the contents thereof; that the facts contained therein are true, to the best of her knowledge and belief; and that she is duly authorized to execute such Application on behalf of Consumers Energy Company.

Kelly M. Hall

Dated: December 16, 2024 By: ______________________

Kelly M. Hall
Deputy General Counsel and Vice President,
Rates and Regulation

ATTACHMENTS

Consumers Energy Company **ATTACHMENT A**

Summary of Present and Proposed Revenue by Rate Schedule
Total Revenue
Case No. U-21806

Line No.	(a) Description	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		$000	$000	$000	%
	Residential Service				
1	Single Family Dwelling A	$ 1,577,268	$ 1,768,761	$ 191,493	12.1
2	Multifamily Dwelling A-1	53,863	57,769	3,906	7.3
3	Total Residential Service	1,631,131	1,826,530	195,399	12.0
	General Service				
4	Small Service GS-1	271,029	287,141	16,112	5.9
5	Medium Service GS-2	224,497	231,882	7,385	3.3
6	Large Service GS-3	55,417	56,442	1,025	1.9
7	Outdoor Lighting GL	-	-	-	NA
8	Total General Service	550,943	575,465	24,522	4.5
9	Total Gas Sales (1)	2,182,075	2,401,996	219,921	10.1
	Transportation				
10	Small Transport ST	34,864	46,678	11,814	33.9
11	Large Transport LT	27,199	34,964	7,765	28.5
12	Extremely Large Transport XLT	30,204	38,128	7,923	26.2
13	Extra Extremely Large Transport XXLT	10,129	10,216	87	0.9
14	Total Transportation	102,396	129,985	27,589	26.9
15	Total Service (Delivery & Fuel)	$ 2,284,471	$ 2,531,981	$ 247,510	10.8
16	Additional Late Payment Charge Revenue	0	498	498	
17	Revenue Increase/(Decrease) Due to Rounding	0	-	(0)	
18	Revenue (Sufficiency)/Deficiency	$ 2,284,471	$ 2,532,479	$ 248,008	10.9

Notes

(1) Includes aggregate billed transportation accounts.

Consumers Energy Company
Summary of Present and Proposed Rates by Rate Schedule
Case No. U-21806

Line No.	(a) Description	(b) Units	(c) Present	(d) Proposed
	Residential Class			
	Single Family Dwelling A			
1	Customer Charge	$/Mth	$ 15.00	$ 20.00
2	Income Assistance - RIA Program	$/Mth	$ (15.00)	$ (20.00)
3	Income Assistance - LIAC Pilot	$/Mth	$ (30.27)	$ (30.27)
4	Distribution Charge	$/Mcf	$ 5.1950	$ 5.8140
	Multifamily Dwelling A-1			
5	Customer Charge	$/Mth	$ 15.00	$ 20.00
6	Excess Peak Charge	$/Mcf	$ 0.0913	$ 0.1217
7	Distribution Charge	$/Mcf	$ 5.1950	$ 5.8140
	General Service			
	Small Service GS-1			
8	Customer Charge - Principal	$/Mth	$ 18.00	$ 24.00
9	Customer Charge - Contiguous	$/Mth	$ 14.00	$ 21.00
10	Distribution Charge	$/Mcf	$ 4.9147	$ 5.1657
	Medium Service GS-2			
11	Customer Charge - Principal	$/Mth	$ 133.32	$ 146.83
12	Customer Charge - Contiguous	$/Mth	$ 40.00	$ 45.00
13	Distribution Charge	$/Mcf	$ 3.5306	$ 3.6914
	Large Service GS-3			
14	Customer Charge - Principal	$/Mth	$ 324.50	$ 437.80
15	Customer Charge - Contiguous	$/Mth	$ 80.00	$ 125.00
16	Distribution Charge	$/Mcf	$ 3.3012	$ 3.3422
	Outdoor Lighting GL			
17	Single Mantle	$/Lum.	$ 6.00	$ -
18	Multiple Mantle	$/Lum.	$ 11.00	$ -
	Transportation			
	Small Transport ST			
19	Customer Charge - Principal	$/Mth	$ 973.32	$ 1,185.81
20	Customer Charge - Contiguous	$/Mth	$ 60.00	$ 105.00
21	Distribution Charge	$/Mcf	$ 1.4273	$ 1.9509
	Large Transport LT			
22	Customer Charge - Principal	$/Mth	$ 2,026.79	$ 4,631.70
23	Customer Charge - Contiguous	$/Mth	$ 60.00	$ 105.00
24	Distribution Charge	$/Mcf	$ 1.3009	$ 1.5374
	Extremely Large Transport XLT			
25	Customer Charge - Principal	$/Mth	$ 16,379.74	$ 17,042.79
26	Customer Charge - Contiguous	$/Mth	$ 60.00	$ 105.00
27	Remote Meter Charge	$/Mth	$ 70.00	$ 70.00
28	Distribution Charge	$/Mcf	$ 0.9564	$ 1.2395
	Extra Extremely Large Transport XXLT			
29	Customer Charge - Principal	$/Mth	$ 43,617.55	$ 41,396.85
30	Remote Meter Charge	$/Mth	$ 70.00	$ 70.00
31	Distribution Charge	$/Mcf	$ 0.5177	$ 0.5278

	(a)	(b)	(c)		(d)	
Line No.	**Description**	**Units**	**Present**		**Proposed**	
	Authorized Tolerance Level (ST, LT, XLT, XXLT) [(2)]					
32	2.0% ATL	$/Mcf	$	(0.0732)	$	(0.0781)
33	4.0% ATL	$/Mcf	$	(0.0507)	$	(0.0540)
33	6.5% ATL	$/Mcf	$	(0.0225)	$	(0.0240)
34	7.5% ATL	$/Mcf	$	(0.0113)	$	(0.0120)
34	8.5% ATL	$/Mcf	$	-	$	-
35	9.5% ATL	$/Mcf	$	0.0113	$	0.0120
35	10.5% ATL	$/Mcf	$	0.0225	$	0.0240
	Customer Attachment Program					
36	Discount Rate	%		7.07		7.35
37	Carrying Cost Rate	%		8.74		9.11
	Other Transportation					
38	Authorized Gas Use Charge	$/Mcf	$	1.00	$	1.00
39	Unauthorized Gas Use Charge	$/Mcf	$	10.00	$	10.00
40	Load Balancing Charge	$/MMBtu	$	0.25	$	0.25
41	EUT Gas In Kind	%		2.45		2.45
	Non-Transmitting Gas Meter - Automated Meter Reading (AMR) Provision					
42	One Time Charge Prior to AMR Install	$/Customer	$	109.94	$	109.94
43	One Time Charge After AMR Install	$/Customer	$	177.53	$	177.53
44	Monthly Charge	$/Customer	$	6.03	$	6.03

Notes

(1) Excludes Outdoor Lighting GL

(2) Only the 2.0% ATL adjustment is available to XXLT and the 4.0% ATL credit is subtracted to get a credit of $(0.024)

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 for other relief.	)))))	Case No. U-21806

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on December 16, 2024, she served an electronic copy of **Consumers Energy Company's Application, a Proposed Notice of Hearing, a Non-modifiable Protective Order, and the Testimony and Exhibits of Consumers Energy Company's Witnesses** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

She further states that she provided the public versions of (i) Consumers Energy Company's Application, a Proposed Notice of Hearing, a Proposed Protective Order, and the Testimony and Exhibits of Consumers Energy Company's Witnesses in PDF format; (ii) exhibits in Excel format that were filed in Excel format; (iii) tariff changes in Word format that were filed in Word format; (iv) Workpapers in PDF format of Consumers Energy's witnesses; and (v) Consumers Energy Company's Part II and Part III Standard Filing requirements via secure filing sharing link at the email addresses listed in Attachment 1.

Melissa K. Harris

Melissa K. Harris

Subscribed and sworn to before me this 16th day of December, 2024.

Crystal L. Chacon

Crystal L. Chacon, Notary Public
State of Michigan, County of Eaton
My Commission Expires: 05/25/30
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-21806
(Including Parties to Case Nos. U-21308 and U-21490)

Party	Mailing Address	Email Address
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Counsel for Retail Energy Supply Association ("RESA")		
Jennifer Utter Heston, Esq.	Fraser Trebilcock Davis & Dunlap, P.C. 124 West Allegan, Suite 1000 Lansing, MI 48933	jheston@fraserlawfirm.com
Counsel for the Lansing Board of Water & Light ("LBWL") and Michigan State University ("MSU")		
Nolan J. Moody, Esq. Cole V. Lussier, Esq.	Dickinson Wright PLLC 123 W. Allegan Street, Ste. 900 Lansing, MI 48933-1816	nmoody@dickinsonwright.com clussier@dickinsonwright.com

* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21806
(Including Parties to Case Nos. U-21308 and U-21490)

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* Receives Confidential Materials

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

REDACTED

DIRECT TESTIMONY

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Heidi J. Myers, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Revenue Requirements and Regulatory Affairs.

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Accounting in 2003 from Michigan State University. I received a Master of Business Administration degree in 2012 from the University of Michigan – Flint. I am also a Certified Public Accountant licensed in the state of Michigan.

Q. Please describe your professional experience.

A. From 2004 to 2008 and from 2012 to 2015, I was employed by the Michigan Public Service Commission ("MPSC" or the "Commission") as an auditor and later as the Manager of the Revenue Requirements Section. From 2008 to 2012 and 2015 to 2017, I was employed by the Lansing Board of Water and Light ("BWL"). During my tenure at the BWL, I held the following positions: Senior Rate Analyst, Executive Financial Assistant, Field Services Supervisor, Manager of Human Resources, and Supervisor of Finance and Planning. I joined Consumers Energy in January of 2017 as a Principal Rate Analyst and was promoted to Director of Revenue Requirements and Analysis in March 2018 and was promoted to Executive Director of Revenue Requirements and Regulatory Affairs in June 2020.

Q. What are your responsibilities as the Executive Director of Revenue Requirements and Regulatory Affairs at Consumers Energy?

A. As the Executive Director of Revenue Requirements and Regulatory Affairs, I am responsible for regulatory stakeholder collaboration and project management for the development of regulatory filings and communications as well as managing and preparing studies related to the level of the Company's revenue requirements, including the preparation, and monitoring of gas and electric rate case filings before the Commission and other financial analyses. In addition, I oversee the calculation of the Company's Gas Cost Recovery and Power Supply Cost Recovery monthly billing factors. Beginning in July 2023, I also assumed responsibility for cost, pricing, and regulatory policy.

Q. Have you previously filed testimony with the Commission?

A. Yes.

Q. Please state the proceedings you have been involved in.

A. I sponsored testimony in the following cases:

Case No. U-14347 – Consumers Energy electric rate case;

Case No. U-14547 – Consumers Energy gas rate case;

Case No. U-17087 – Consumers Energy electric rate case;

Case No. U-17473 – Consumers Energy securitization;

Case No. U-18322 – Consumers Energy electric rate case;

Case No. U-20102 – Consumers Energy electric credit A;

Case No. U-20103 – Consumers Energy gas credit A;

Case No. U-20134 – Consumers Energy electric rate case;

Case No. U-20165 – Consumers Energy integrated resource plan;

Case No. U-20286 – Consumers Energy electric credit B;

Case No. U-20287 – Consumers Energy gas credit B;

Case No. U-20309 – Consumers Energy calculation C;

Case No. U-20697 – Consumers Energy electric rate case;

Case No. U-20889 – Consumers Energy securitization;

Case No. U-21389 – Consumers Energy electric rate case;

Case No. U-21490 – Consumers Energy gas rate case; and

Case No. U-21585 - Consumers Energy electric rate case.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide an overview of the Company's gas general rate case filing. I introduce key proposals included in this case and provide a brief introduction to the Company's witnesses and the topics supported in their respective testimony and I discuss the requirements for the Company's next gas rate case (i.e. this case) as set forth in the approved settlement agreement in the Commission's July 23, 2024 Order in Case No. U-21490. Finally, I describe the amounts included for recovery in this case related to the SAP S/4HANA Implementation Project ("SAP Project") and request the deferral of related operating and maintenance ("O&M") expense and an adjustment to the amortization period of the cloud implementation cost for the software as a service ("SaaS") solutions associated with the project.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibit:

Confidential Exhibit A-79 (HJM-1)	SAP S/4HANA Implementation Project – Revenue Deficiency Impact of O&M Deferral.

COMPANY OVERVIEW

Q. Please provide a brief description of Consumers Energy and its service territory.

A. Consumers Energy is a combination electric and gas utility that has powered Michigan's progress for 138 years. The Company provides natural gas service to approximately 1.8 million customers in Michigan's lower peninsula.

CASE OVERVIEW

Q. Please summarize the key drivers of the Company's request in this case.

A. The Company requests rate relief in the amount of $248 million, which is summarized in Table 1:

Table 1

	(In Millions)
Investment	$ 135
Cost of Capital	$ 44
ASP Gain Previously Used to Offset Revenue Requirement[1]	$ 27
Operating Expenses	$ 42
Rate Relief	**$ 248**

Q. How does this request impact residential customer bills?

A. The Company anticipates that the average monthly residential bill for the 12 months ending October 2026 will increase by 12.1% over current rate levels. If the entirety of this request is approved, Consumers Energy expects that the average residential natural gas customer

[1] Pursuant to the approved settlement agreement in Case No. U-21490, $27.5 million of the gain on the sale of the unregulated Appliance Service Plan ("ASP") business was used to reduce the required revenue requirement for that case. This base rate reduction does not carry forward to the test year of this case.

will pay approximately $2.94 per day in 2026 for the natural gas service that provides an affordable fuel for heating, cooking, and hot water.

The Company is aware that this increase will challenge some customers more than others. Recognizing the challenges some customers face, the Company offers a range of assistance options, including the Consumers Affordable Resource for Energy Program, a Residential Income Assistance credit, and a Low-Income Assistance Credit for qualifying customers. These programs are designed to assist customers with the management of their energy use and bills. In addition to these provisions and programs, the Company and its employees are generous contributors to community-based groups, including the United Way, the Salvation Army, the Heat and Warmth Fund, and many community service organizations. The Company works to keep its requested price increases to the lowest level it believes is reasonable, while balancing the need for safety, reliability, improved customer service, and increasingly clean natural gas service.

INTRODUCTION OF WITNESSES

Q. Please identify the other witnesses presenting direct testimony in support of the Company's filing and the topic that each witness will be addressing.

A. The following witnesses will also be providing testimony on behalf of Consumers Energy in this filing:

- **Mustafa Ahmed** supports the Company's gas revenues and deliveries in the test year.
- **Stacy H. Baker** supports the IT Departments, capital expenditures, and O&M expenses that are needed to maintain existing IT systems, enable new security capabilities, and support other technology needs as proposed in the case. Ms. Baker also describes the Company's capital spending and O&M expenses related to cyber security operations and physical security, as well as the need for increased staffing and O&M to respond to evolving security threats and a changing regulatory landscape.

- **Corey Ballinger** describes the function and needs of the Company's fleet services and supports the fleet capital investment and electrification strategy.

- **Marc R. Bleckman** supports the Company's proposed capital structure and cost of capital which should be used in computing overall rate of return. Mr. Bleckman also provides support for the level of cash included in the Company's test year working capital.

- **Ann E. Bulkley** supports the Company's proposed return on equity that should be used in computing the overall rate of return.

- **Jessica Byrom** describes the work performed by the Company's Customer Experience & Operations organization and how this work benefits customers. Ms. Byrom also supports the capital investment and O&M expense associated with executing this work.

- **Amy M. Conrad** describes the Company's overall compensation philosophy and provides support for the recovery of costs related to the Company's annual Employee Incentive Compensation Program ("EICP") at target levels.

- **Neal P. Dreisig** provides an overview of the Company's gas transmission, distribution, and storage and compression systems along with an updated version of the Company's 10-year plan or the Natural Gas Delivery Plan ("NGDP").

- **Matthew J. Foster** supports the Company's Corporate Services O&M expense which includes uncollectible expense, and injuries and damages. Mr. Foster's testimony also supports Corporate Services capital spending, IT projects supporting Corporate Services, manufactured gas plant remediation cost recovery, and the request for certain accounting approvals.

- **Samuel M. Geller** sponsors the Company's gas cost of service study that conforms to methods previously approved by the Commission. He also provides a version of the cost-of-service study that incorporates Company proposals addressing cost of service study issues raised in Case No. U-21490.

- **Michael P. Griffin** supports certain gas transmission and distribution capital and O&M expenses primarily related to the operations of the Company's high-pressure distribution and transmission system.

- **Kendra K. Grob** supports the Company's costs related to retirement, health care, life insurance, long-term disability plans, and other benefits provided to its employees and retirees. Ms. Grob's testimony also supports the continuation of the Defined Benefit ("DB") Pension/Other Post-Employment Benefits ("OPEB") Volatility Mechanism.

- **Quentin A. Guinn** describes the function and needs of the Company's facilities and supports proposed capital spending and O&M expenses related to the Gas business portion of Facility Operations.

- **Kirkland D. Harrington** presents the Company's proposed tariff language changes to its gas rate schedules.

- **Timothy K. Joyce** supports the Company's Gas Compression and Gas Storage Capital spending and Gas Compression O&M expense. Mr. Joyce's testimony also sponsors IT projects supporting Gas Compression and Gas Storage, cost of gas sold and underground, lost and unaccounted for gas, and company use gas.

- **Ashley E. Meschke** discusses operational performance goals included in the Company's EICP and how the EICP goals provide benefits to customers.

- **Kristine A. Pascarello** supports Gas Engineering and Supply O&M expense as well as certain gas distribution capital investments.

- **James P. Pnacek** supports Gas Operations Division O&M expense as well as certain gas distribution capital investments. Mr. Pnacek also sponsors IT projects supporting the Gas Operations Division.

- **Heather M. Prentice** describes former manufactured gas plant sites at which the Company has a present or former ownership interest and provides environmental requirements for investigation and remediation. Ms. Prentice also identifies and describes expenditures for associated environmental response.

- **Heather L. Rayl** presents the historic and test year revenue deficiency. Ms. Rayl also presents support for requested approval to follow Federal Energy Regulatory Commission ("FERC") accounting treatment for first-time and one-time maximum allowable operating pressure retesting costs.

- **S. Austin Smith** presents the Company's rate design proposals.

- **Brian J. VanBlarcum** supports the Company's real and personal property taxes as well as the excess deferred federal income taxes being returned to gas customers because of the Tax Cuts and Jobs Act of 2017.

- **Lincoln D. Warriner** supports certain gas distribution capital investments related to the New Business, Asset Relocation, Regulatory Compliance, and Capacity/Deliverability programs.

CASE HIGHLIGHTS

Q. How does the outcome of Consumers Energy's most recent gas general rate case impact the requested rate relief in this case?

A. Consumers Energy's most recent gas rate case, Case No. U-21490, resulted in a Commission-approved Settlement Agreement with new rates that were implemented in October 2024. Consumers Energy continues to invest in its natural gas system and supporting infrastructure; therefore, this application includes the request to recover actual and projected costs related to these ongoing investments. As shown in Table 1, this request is largely driven by new investment.

Q. Are there any provisions from the Settlement Agreement in Case No. U-21490 that impact this filing?

A. Yes. The settlement agreement in Case No. U-21490 provided for the sharing of the net upfront gain from the sale of its unregulated Home Energy Products Program. $27.5 million, or one fourth of the net upfront gain, was used as an offset to the revenue deficiency in lieu of additional rate relief during the test year of Case No. U-21490. The remaining three fourths of the net upfront gain, approximately $82.5 million, will be credited back to customers, through the Home Products Credit over a three-year period extending through September 30, 2027. Company witness Smith sponsors the calculation of the credit to be effective on November 1, 2025.

The settlement agreement provided that the long-term service agreement ("LTSA") portion of the Home Products Credit could be modified in future rate cases. The Company has removed the LTSA margin from the Home Products Credit and has included it in base rates. Company witness Byrom supports the margin included in the case related to the LTSA.

Company witness Pascarello's testimony and exhibits provide details regarding the Company's compliance with the settlement agreement's requirements regarding the Enhanced Infrastructure Replacement Program ("EIRP"). Her testimony discusses expectations of meeting the various spending requirements based on region and the type of pipe used for replacements.

Company witness Geller sponsors a Cost-of-Service study version that shows a more granular allocation of Other Distribution Plant by FERC account and a cost-of-service version that calculates the impact of utilizing the Average and Excess allocation. Mr. Geller's testimony also includes a detailed analysis of FERC Account 378, as required by the settlement agreement.

Company witness Smith explains how the Company is complying with the requirement to examine the breakeven points and bring the breakeven points and the customer charges closer to cost of service.

Q. How do the Company's proposals in this case support the Company's NGDP?

A. Consumers Energy has plans for investing in its natural gas system over the course of the next decade to ensure customers continue to receive safe, reliable, and affordable natural gas while transforming the system to deliver cleaner fuels for a decarbonized future. The NGDP outlines the Company's 10-year plan to provide a transparent investment plan considering a safe and reliable gas supply, how the Company plans to evolve its assets in accordance with the Gas Pipeline Safety Management Systems framework, and a strategic framework in response to decarbonization goals of the Company's natural gas customers and future carbon policy relevant to the utility. The proposals in this rate case support the objectives of the NGDP. Company witnesses Dreisig, Joyce, Griffin, Warriner, Pascarello, and Pnacek provide support for the transmission and distribution system investments and O&M programs.

Q. Why is Consumers Energy making significant natural gas investments?

A. Consumers Energy has built and maintained a complex natural gas system comprising of approximately 30,700 miles of distribution and transmission pipelines. The Company operates 15 storage fields and 8 compressor stations, and all of these systems have served customers well for decades, allowing access to a diverse natural gas supply and leveraging the unique size of the Company's storage fields to time gas purchases and stabilize pricing. It is crucial that Consumers Energy continue to invest in the system to ensure natural gas is delivered safely, reliably, and affordably to the approximately 1.8 million natural gas customers who rely on it every day.

Q. How should stakeholders view the Company's natural gas investment?

A. Consumers Energy's investment represents its commitment to modernizing the Company's natural gas pipelines and continued improvements in energy efficiency. The EIRP continues to replace significant portions of the Company's infrastructure annually, resulting in a safer, more resilient system that has fewer leaks, thereby reducing carbon emissions. Additionally, the Company continues to work with third parties through its damage prevention program and third-party coordination efforts to mitigate and reduce third party-caused leaks on the system. The investments, outlined in the NGDP, express the multitude of initiatives the Company is undertaking to ensure the sustainable delivery of safe, reliable, clean, and affordable energy to customers.

Q. Is the Company proposing any deferrals related to critical gas operation costs?

A. Yes. As detailed in the testimony of Company witnesses Pnacek and Pascarello, the Company is requesting the ability to defer any test year revenue requirement of capital and O&M expense that occur as a result of updates to Leak Detection and Repair rules and requirements to comply with the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). The Company anticipates requirements to comply with PHMSA that relate to safety and reporting. These rules are expected to be updated after the filing of this application and will require repairs and upgrades to be completed during the test year.

Consumers Energy also proposes to defer O&M spending related to staking. While the Company attempts to forecast staking volumes with a high degree of accuracy, increasing staking volumes and external factors contribute to volatile expenditures. This request would avoid potential constraints on other important programs in the event higher than anticipated staking costs outside of the Company's control are incurred. Company witness Pnacek also addresses this topic in his testimony.

Q. How do IT and security proposals provide value to customers?

A. As described in more detail below, the Company is beginning a critical upgrade to its SAP system that has a direct tie to being able to keep Company and customer information safe and secure. In addition to investments in IT, the Company proposes continuing investments in the Security Department's ability to provide 24/7 physical and cyber security to ensure protection for the Company's critical infrastructure and maintain customers' privacy by keeping their sensitive data safe. Security risks to the Company have never been greater, and the Company must keep pace with the rising threats to maintain essential services and recover quickly in the event of a security incident. The

Company is improving its focus on security across its operations with increased staffing levels to support 24/7 security monitoring through the Fusion Center — a dedicated team with oversight for physical and cyber security, increased use of cloud computing solutions, and ongoing investment in maturing security capabilities to protect technology and physical infrastructure. Company witness Baker addresses the Company's proposals for security and IT.

Q. Does the Company evaluate major capital projects and O&M expenses on an ongoing basis?

A. Yes. The Company continually evaluates and adjusts its planning for a variety of factors including (i) sales and revenue expectations and results, (ii) infrastructure investments and the cost of capital, (iii) O&M expense expectations and results, and (iv) the impact of several other variables that may change over time (including changes to environmental laws and requirements, Commission orders, weather, customer demands, commodity prices, financing costs, changes in economic expectations, etc.). In any one period, the Company's capital investments and its O&M expenses may vary from what was expected in a prior period. The Company plans for this continually changing environment, and its witnesses have provided highly detailed and thorough support for capital expenditures and O&M expenses.

The individual witnesses addressing capital and O&M costs in this case explain the reasons for these expenditures. The Company employs a rigorous management review process, which ensures that the allocation of O&M and capital resources are optimized such that the Company's strategic, financial, and operational plans are aligned to deliver customer value. The Company maintains a portfolio of investment opportunities from which to make investment decisions, with the goal of maximizing customer value while minimizing the cost impact to customers. While the Company must retain the flexibility to react to changing conditions, the proposed expenditure levels included in this case reflect the Company's commitment to meet its legal obligations and improve service reliability and quality for customers.

Q. Does the Company anticipate the need to flex spending between programs in the test year?

A. Yes. The Company's plans provide its best estimate of the total cost it expects to spend on each program. However, when actual dollars are spent in the test year, unforeseen circumstances (such as new business, extreme weather, or unanticipated civic improvement projects undertaken by state or local governments, for example) may require the Company to adjust the spending between programs. In any given year, the Company may be required to undertake unplanned natural gas distribution infrastructure replacement projects. In this circumstance, the Company would need to compensate for this unforeseen spending by adjusting the amount it intended to spend on another program. It is not possible for Consumers Energy to anticipate every event or circumstance which may cause it to incur costs on behalf of its customers, so it is prudent to allow for some flexibility in spending.

Q. Is the Company requesting to continue a DB Pension/ OPEB Volatility Mechanism?

A. Yes. DB Pension/OPEB expenses are sensitive to changes in asset returns or other assumptions that create a significant potential for volatility in future expenses. As discussed in the testimony of Company witness Grob, the Company is requesting the ability to continue its currently in place mechanism which provides benefit to customers by eliminating the risk of future expense volatility.

<u>SAP S/4HANA IMPLEMENTATION PROJECT RECOVERY</u>

Q. Describe the SAP Project.

A. The SAP Project will modernize the Company's current Enterprise Resource Planning SAP solution that will reach the end of mainstream vendor maintenance on December 31, 2027. The completion of this project is crucial. Operating the system beyond the end of support date creates significant risks including the inability to comply with regulatory mandates, perform core customer supporting business operations, and apply the latest security patches that are critical for cyber security protection. The project is described in more detail in the testimony of Company witness Baker.

Q. Please describe amounts included in this rate case related to the SAP Project.

A. The Company has included [redacted] of test year capital spending and [redacted] of O&M expense in the case. None of the capital spending will close to plant in service during the test year of this case. As a result, the case does not include any of the associated depreciation expense and the return on amounts included in construction work in progress have been offset by allowance for funds used during construction. Simply put, there is no financial impact to the case resulting from the capital spending. The O&M expense has a dollar for dollar or [redacted] impact on the revenue deficiency.

Q. How does the Company propose to address the O&M expense for this project?

A. The Company is proposing to defer the associated O&M expense for the project and amortize it over 15 years consistent with the life of the assets. This approach will prevent the need for customers to fund spikes in the Company's IT O&M expense during the project and will instead smooth the collection over the life of the asset. The deferral will also tie the recovery to the time period over which the spending will be providing benefits to the Company and customers. This is the most appropriate method of recovering the O&M expense related to the SAP project.

Q. If the proposed deferral is approved how will the case be impacted?

A. If the deferral is approved, the revenue deficiency of the case should be lowered by [redacted]. As shown on Confidential Exhibit A-79 (HJM-1), this reduction includes the removal of the O&M expense replacing it with the inclusion of the expense as a deferral in working capital.

Q. Does the implementation of this deferral require any specific accounting approvals?

A. Yes. The proposed deferral would result in deferred debits to be amortized over 15 years. The Company requests approval to recognize a regulatory asset to record these deferred expenses.

Q. Are there are any other requests related to the SAP Project?

A. Yes. The Company also requests a 15-year amortization for the cloud implementation costs for the SaaS solutions to create consistency of recovery for all aspects of the cost of the SAP Project. This would lengthen the amortization period from being tied to the duration of the initial license to the life of the asset that anticipates relicensing over the life of the asset. This provides customer benefit by spreading these costs over a longer period and matching the recovery to the period over which this spending will provide benefit to the Company and customers.

Q. Please summarize your direct testimony.

A. Consumers Energy respectfully submits this request for $248 million in annual rate relief. Consistent with Consumers Energy's commitment to provide exceptional value and service to every customer, caring for the communities where we live and work, and delivering on investor expectations, the Company is requesting revenue recovery for infrastructure investments that primarily support the NGDP, as well as other programs that will enhance the customer experience. Consumers Energy is committed to delivering customer value and improving customer service and believes that this filing is a representation of the commitment put forth in the Company's purpose – World Class Performance Delivering Hometown Service.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

MUSTAFA AHMED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Mustafa Ahmed, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am a Senior Sales Forecasting Analyst in the Financial Planning & Analysis Department.

Q. Please state your educational background.

A. I graduated from University of Windsor in October 2011, with a Bachelor of Commerce in Honors Business Administration degree. I have also obtained CPA, CA (Certified Professional Accountant and Chartered Accountant) designation in July of 2013. In addition, I have completed the regulatory accounting course for utility ratemaking and forecasting.

Q. What is your regulatory experience?

A. Prior to joining the Company, from October 2011 through May 2022, I worked in both public accounting and corporate industry. I started in Public Accounting in positions of Staff Accounting and worked up to a Senior Associate/Manager. I then worked in corporate industry as an Accounting Analyst and Financial Analyst. I joined Consumers Energy in May 2022 as a Senior Financial Analyst (supporting the gas utility) in the Financial Planning and Analysis Department. I joined the Sales Forecasting team in January 2024, and now perform the gas sales forecasting duties.

Q. Please explain the purpose of your direct testimony in this proceeding.

A. I am presenting the Company's forecasted gas delivery and customer count levels used to design test year rates in this case. I will discuss the observed historic gas deliveries, customer counts, and operating revenues. My direct testimony will address the development of the forecasts used in this case.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following exhibits:

Exhibit A-5 (MA-1)	Schedule E-1	Annual Service Area Deliveries by Major Customer Classes and System Output 5-Year Historical;
Exhibit A-5 (MA-2)	Schedule E-1a	Summary of 2023 Historical Year Revenues;
Exhibit A-5 (MA-3)	Schedule E-2	2023 Historical Year Consumption and Customer Counts;
Exhibit A-5 (MA-4)	Schedule E-3	2023 Historical Year Operating Revenues;
Exhibit A-15 (MA-5)	Schedule E-1	Market Outlook: 5-Year Annual Calendar Gas Forecast by Class;
Exhibit A-15 (MA-6)	Schedule E-2	Test-Year Cycle Gas Deliveries Forecast by Class;
Exhibit A-15 (MA-7)	Schedule E-3	Test-Year Cycle Gas Deliveries by Rate Schedule;
Exhibit A-15 (MA-8)	Schedule E-4	Test-Year Authorized Tolerance Levels by Rate Schedule;
Exhibit A-15 (MA-9)	Schedule E-5	Market Outlook: 5-Year Average Customer Forecast by Class;
Exhibit A-15 (MA-10)	Schedule E-6	Test-Year Customer Count Forecast by Class;
Exhibit A-15 (MA-11)	Schedule E-7	Test-Year Total Customer Count Forecast by Rate Schedule;

Exhibit A-15 (MA-12)	Schedule E-8	Calculation of Test-Year Projected Income Assistance Enrollments;
Exhibit A-15 (MA-13)	Schedule E-9	Calculation of Test-Year Excess Peak Consumption; and
Exhibit A-15 (MA-14)	Schedule E-10	Transition from 2023 Historic Actuals to 12 Months Ending October 2026 Test-Year Revenues, Deliveries, and Customers.

Q. Were these exhibits prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the current weather normalization process.

A. The Company contracted with Itron to develop a set of economic models to quantify the weather affects. The models developed by Itron take into consideration the various weather responses by rate class (residential, commercial, and industrial), customer counts, weather trends, billing days, and responses at various temperature levels (55 degrees Fahrenheit versus 65 degrees Fahrenheit).

Q. How well do the econometric models explain the observed variations in gas deliveries?

A. Six main econometric models are used to explain the variation in gas delivery by class (residential, commercial, and industrial) and service type (sales and transportation). For instance, the total variation in residential gas deliveries due to temperature is explained using a residential sales model and residential transportation model. Similar models are used for commercial and industrial gas deliveries. The model is robust and performs well in explaining the variation in gas deliveries.

Q. How accurate was this weather normalization process in 2023?

A. Consumers Energy's weather adjusted calendar deliveries for 2023 totaled approximately 308.4 Bcf, compared to the Company's budgeted calendar deliveries of approximately 311.3 Bcf, or roughly 0.9% below the Company's anticipated deliveries.

Q. Please explain Exhibit A-5 (MA-1), Schedule E-1.

A. Exhibit A-5 (MA-1), Schedule E-1, is a summary of the five-year Historical Annual Service Area Deliveries by Major Customer Classes and System Output. This exhibit is filed in accordance with the Commission's directive in Case No. U-18238.

Q. Please provide a summary of the 2023 operating revenue based on the actual customer and gas delivery levels for the historical year.

A. The 2023 historical operating revenue is presented in Exhibit A-5 (MA-2), Schedule E-1a, by rate schedule. A detailed summary of customer counts and deliveries is provided in Exhibit A-5 (MA-3), Schedule E-2, by rate schedule and type of service (sales, customer choice, transportation, and aggregation). The components of the 2023 historical operating revenues are shown in Exhibit A-5 (MA-4), Schedule E-3. These exhibits are also filed in accordance with the Commission's directive in Case No. U-18238.

Q. Please summarize Consumers Energy's gas forecasting process.

A. In general, the gas forecasts are based on regression analysis, a mathematical and statistical technique that correlates the relationship between dependent variables (deliveries and customer counts) and independent variables (economics and/or weather). Applying these relationships to expected independent variables allows the Company to project the corresponding movements in dependent variables. The four major classes of gas deliveries (sales plus transportation) that are forecast are residential, commercial, industrial, and interdepartmental. For each of these classes, monthly forecasts are developed on a cycle billed (billing month) basis and then adjusted to calendar month amounts using the methodology described later in my direct testimony. Moreover, the impact of exogenous factors – e.g., incremental energy efficiency – is applied ex post.

Q. Please describe the different models used to develop the gas deliveries and customer count forecasts.

A. Regression analysis is used to develop forecast models that estimate numerical coefficients applied to weather and economic indicators to estimate future gas consumption. The regression models were evaluated against various measures to ensure that reasonable forecasts were generated. For instance, each model was reviewed to validate that the drivers were theoretically sound, model coefficients were statistically significant, and model variables explained historical and current market conditions.

Q. Please briefly describe the economic data used in the forecast process.

A. Historical and projected service sector employment and manufacturing employment are included as independent variables in the forecasting process. These indicators are from the forecasts of Michigan economic activity obtained from IHS Markit.

Q. Please briefly describe the weather data used in the forecast process.

A. The gas delivery forecasts assume normal weather based on the 15-year mean. Under this method, the daily temperature is used to calculate monthly heating degree days. The 15-year mean of the monthly heating degree days is then used to represent future expected weather impacts.

Q. Why does the Company use the regression model approach to forecast sales?

A. Regression modeling has been approved by the Commission in Case Nos. U-17643, U-17882, U-18124, U-18424, U-20322, U-20650, U-21148 and U-21308. Regression analysis is a statistical process used to predict an outcome based on the relationship between a dependent variable (deliveries, average usage, or customers) and independent variable(s) (weather and economy). For instance, a regression model is used to predict average residential monthly usage based primarily on future expectations of normal weather occurring during the test year. Each model is evaluated for reasonableness – i.e., is it theoretically logical – and statistical significance as part of the forecasting process. Regression analysis is used to develop gas delivery and customer count forecast models based on weather and economic variables. Each model is selected based on its ability to properly explain variations in historical data – i.e., how well it fits the data – along with the statistical significance of the model coefficients. Particularly, I evaluate regression model performance based on the adjusted coefficient of multiple determination (R_a^2) and Mean Absolute Percent Error ("MAPE"). In addition, I also examine the t-statistics and p-values associated with the model coefficients.

Q. Please explain the use of R_a^2 and MAPE.

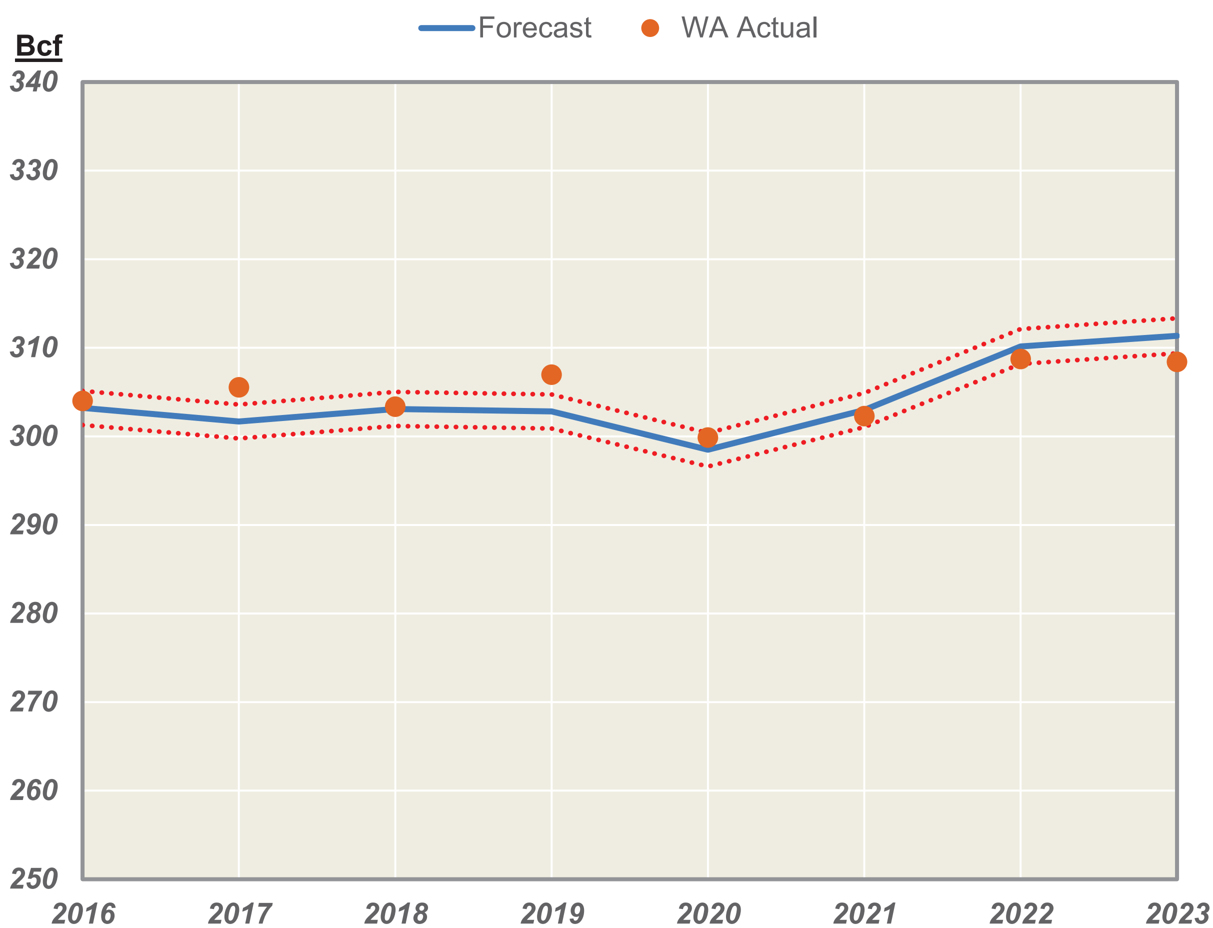
A. Both of these statistical tests are used to evaluate how well the models fit the historical data, and also provide a good indication of how well the models will perform in the forecast period. The R_a^2 measures the ability of the models to explain variations in the historical data. An R_a^2 of unity suggests that a model explains all of the variations in the data; whereas, an R_a^2 of zero suggests it explains none of the variations. For example, if regression models have R_a^2 values above 0.9, this suggests that at least 90% of the variation in the data is explained by the models. In most cases, the models used in the Company's forecasting process have values in excess of 0.95. In addition, I consider the MAPE values to gauge overall model performance. Essentially, the MAPE is used to measure the model errors in which smaller values suggest better model performance. MAPE values between 5% and 10% are generally considered ideal, although higher values may also be deemed acceptable based on other considerations, such as the R_a^2. The regression models used in the Company's forecasting process generally have MAPE values below 10%.

Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.

A. Regression analysis is used to develop models that minimize the variance between the actual data and estimates from the models based on the relationship between dependent and independent variables. A numerical coefficient (β) is estimated for each independent variable in the model and represents the best linear unbiased estimate for that variable's contribution toward explaining the dependent variable. The t-statistics and p-values are used to gauge the relevance of each independent variable in the model. The t-statistics and p-values measure the statistical significance of including a particular independent variable based on a probability distribution. A t-statistic above 2 and p-value below 5% for a particular β suggests the independent variable is statistically significant and is appropriate to include in the regression model. Independent variables with t-statistics below 2 and p-values above 5% suggest the variable should be excluded from the model since it does little to explain the dependent variable. In addition, I also consider the direction (positive or negative coefficient sign) and magnitude of each coefficient when determining to include or exclude variables from the models.

Q. You claim the regression model approach produces superior results. How accurate has the Company's forecast been historically?

A. The Company's forecast accuracy can be seen in the graph below. The standard deviation from 2016 through 2023 is 2.6 Bcf and the MAPE is only 0.6%.



Q. What is the forecast of natural gas deliveries for the test year and five-year outlook?

A. Total calendar deliveries are expected to decrease slightly from historic weather normal actuals of 308.4 Bcf in 2023 through the test year. Over the next five years, total deliveries are projected to decrease to 305.8 Bcf by 2029. However, the growth or loss in gas deliveries is not symmetric across all classes. The total and class level gas delivery annual forecasts for 2025 through 2029 are provided in Exhibit A-15 (MA-5), Schedule E-1.

Exhibit A-15 (MA-6), Schedule E-2, provides the 12 months ending October 2026 test year 15-year calendar weather normalized deliveries on a monthly basis, by class, in accordance with Commission filing requirements.

Q. Please explain the process used to separate the test year deliveries by rate schedule.

A. The test year forecast is allocated to the various rate schedules based on the 2023 historical deliveries. The results of the allocation process are provided in Exhibit A-15 (MA-7), Schedule E-3, and Exhibit A-15 (MA-8), Schedule E-4.

Q. Please describe the forecast of customer count levels in the test year and five-year outlook.

A. Total customer counts are projected to increase 1.5% from 1,820,118 in 2023 to 1,846,894 in the 12 months ending October 2026 test year. Over the next five years, the customer level is expected to increase 0.5% per annum with most of this growth occurring within the residential class. The total and class level forecasts are provided in Exhibit A-15 (MA-9), Schedule E-5, and Exhibit A-15 (MA-10), Schedule E-6.

Q. Please describe the process used to separate the customer forecasts by rate schedule.

A. The test year customer forecast is allocated to the various rate schedules based on the 2023 historical customer count levels. The results of the allocation process are provided in Exhibit A-15 (MA-11), Schedule E-7.

Q. Please discuss the process used to forecast the level of consumption and customers enrolled in the Company's income assistance program.

A. The number of expected enrollments is 87,000 customers per month based on the 12-month average of the most recent history. The average residential usage for the test year is applied to this level of customers to develop the consumption set forth in Exhibit A-15 (MA-12), Schedule E-8.

Q. Please describe the process used to forecast the level of excess peak demand.

A. The test year excess peak demand consumption associated with residential multi-dwelling service is based on the peak month consumption and customer levels in accordance with the Company’s natural gas tariffs and is provided in Exhibit A-15 (MA-13), Schedule E-9.

Q. Please provide a summary of the change in revenues, customers, and gas deliveries from the 2020 historical year to the test year.

A. Exhibit A-15 (MA-14), Schedule E-10, provides a summary of the change in revenue, customer levels, and gas deliveries from the 2023 historical year to the 12 months ending October 2026 test year.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

REDACTED

DIRECT TESTIMONY

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Stacy H. Baker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. How long have you worked for Consumers Energy Company ("Consumers Energy" or the "Company") and what positions have you held?

A. I have worked for the Company for over twenty-three years in various individual contributor and leadership positions. The first nine years were in the Finance Department as an Accounting Analyst performing responsibilities to support Payroll and Accounts Payable and later as the Payroll Manager during the SAP Implementation. Thereafter, I moved to the Information Technology ("IT") Department where I have held a number of positions including Enterprise Resource Planning ("ERP") Portfolio Manager, Director of Business Relationship Management – Corporate Services, and Executive Director of IT Business Technology – Corporate Services. In these roles I focused on technology supporting corporate areas of the Company and had IT departmental responsibility for the delivery and operation of IT applications for Finance, Human Resources ("HR"), Supply Chain, Legal and Government, Regulatory & Public Affairs. I am currently the Director of Technology Portfolio Office responsible for portfolio management of the Company's IT, Security, and Operational Technology ("OT") assets, project management office including agile services, project delivery organization, and organizational change management. This includes the management of the IT long-term financial plan, administration of portfolio management, cloud financial management, development of testimony and exhibits, and supporting rate cases for the IT Department.

Q. Would you please state your educational background?

A. I earned a Bachelor of Science in Business Administration degree from Central Michigan University in December 1992 with a major in Accounting.

Q. Have you ever testified in any other proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I testified in the following cases:

- Case No. U-21308 – 2022 Gas Rate Case; and
- Case No. U-21490 – 2023 Gas Rate Case.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to describe the Operating and Maintenance ("O&M") expenses and capital expenditures needed by the IT Department to maintain and secure existing IT and security systems and enable new capabilities and services to support safe, affordable, and reliable natural gas. I also provide an overview of increasing threats in both Cyber Security and Physical Security areas, their evolution over time, and the changing regulatory landscape that necessitates increased O&M funding. These increases are essential for advancing cloud computing solutions, maturing security capabilities, and protecting the Company's technology and physical infrastructure.

Furthermore, my direct testimony provides an explanation of the Company's plans for deterring threats before they impact the Company and its customers, detecting malicious activity, and recovering quickly with minimal impact while complying with all regulations.

The benefits of increasing technology use for customers, and the Department's support of the Company's commitments outlined in the Natural Gas Delivery Plan ("NGDP") will also be highlighted. Lastly, the importance of achieving full recovery of the requested expenses and expenditures to provide the best value to the Company's customers will be demonstrated.

Q. Please summarize the main portions of this testimony.

A. My direct testimony discusses the following:

- The importance to customers of digital investments and the role of IT to build and support those investments;
- Changes in the functions of the IT Department;
- Support for Operational O&M expense funding;
- A description of the investment, both O&M and capital, needed to keep the Company's systems secure, current, stable, and supporting new capabilities;
- Definition and rationale for the use of reduced Rough Order of Magnitude ("ROM") estimates and explanation of the difference from contingency requests;
- An explanation of the projects included in this rate case filing for the IT Department and their supporting business plans, as described in Confidential Exhibits A-20 (SHB-5) and A-21 (SHB-6);
- Company action to address previous Commission concerns, including:
    - Company total one time project cost across multiple years,
    - Total Company cost of ownership of each project beyond initial one-time project investment,
    - Recurring hard savings over the life of the investment, and
    - Cost benefit ratio calculated by the Company's internal Business Planning System ("BPS");
- Individual project synopses and requests to support gas and customer plans;

- Individual project synopses and requests to support corporate functions crucial to running an efficient business;

- Individual IT project synopses with supporting, detailed exhibits for the Asset Refresh projects and the Application Currency projects;

- Individual IT project synopses with supporting, detailed exhibit (Exhibit A-24 (SHB-9) for Enhancement projects, along with a detailed worklist of the enhancement work backlog found in Exhibit A-25 (SHB-10);

- Individual IT project synopses for the IT/Digital Foundations and Capabilities projects;

- Further information about and justification of several larger and more complex projects for which projected spending varies from amounts forecasted in Case No. U-21490, including the following projects:

  - Gas Supervisory Control and Data Acquisition ("SCADA") Software Solution,

  - Asset Refresh Program ("ARP") – Field Device Asset Management ("FDAM"),

  - ARP-Radio,

  - ARP-Server and Storage,

  - ARP – Workstation Asset Management ("WAM"),

  - SAP High-performance ANalytic Appliance ("HANA") Database Migration, and

  - IT Operations Management – Service Operations; and

- Further information about and justification of the more complex SAP S/4HANA Implementation project.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit A-17 (SHB-1)	Summary of Actual and Projected Information Technology Operations O&M Expense for the Years 2023, 2024, 2025, and Test Year 12 Months Ending October 31, 2026;

Exhibit A-18 (SHB-2)		Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance for the historical years 2023 - 13-month balance ending December 31, 2024, and for the projected years 2025 – 13-month balance ending October 31, 2026;
Exhibit A-19 (SHB-3)		Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2023, 2024, 2025, and Test Year 12 Months Ending October 31, 2026;
Exhibit A-12 (SHB-4)	Schedule B-5.1	Projected Capital Expenditures Information Technology Summary of Actual and Projected Gas and Common Capital Expenditures;
Confidential Exhibit A-20 (SHB-5)		Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses for the Years 2023, 2024, 2025, and 2026;
Confidential Exhibit A-21 (SHB-6)		Business Case Executive Summaries for Historical, Bridge Period, and Test Year Projects;

Exhibit A-22 (SHB-7)	Asset Refresh Programs Projected Gas and Common Capital Expenditures, For the Projected Year 2025 and Test Year Ending October 31, 2026, and For the Historical and Projected Years 2023 and 2024;
Confidential Exhibit A-23 (SHB-8)	Application Currency Programs Projected Gas and Common Capital and O&M Expenditures for the Years 2025, 2026, and Test Year 12 Months Ending October 31, 2026;
Exhibit A-24 (SHB-9)	Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis;
Exhibit A-25 (SHB-10)	Enhancement Worklist Detail for Years 2016 through March 15, 2024; and
Confidential Exhibit A-26 (SHB-11)	Projected 13-Month Average of IT S4/HANA Cloud Implementation Costs for the projected years 2025 – 13-month balance ending October 31, 2026.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

<u>DESCRIPTION OF THE IT DEPARTMENT</u>

Q. Please describe the purpose of the IT Department.

A. The purpose of the IT Department is to provide and maintain reliable and secure digital solutions and services that support the delivery of business objectives, including execution of the Company's NGDP. Inherent in those objectives are the Company goals to provide a safe, reliable, affordable, and clean gas supply.

The IT Department strives to find the appropriate balance of value and cost in digital solutions. The Company's evolving and pragmatic approach to digital solutions supports many best practices, including:

- Executing work in an efficient and effective manner while remaining flexible as deliverables change by adopting agile frameworks and platform and product-centric operating models that allow the Company to adjust to changing demands on the IT system;
- Equipping coworkers with digital skills through training that enable them to deliver business value faster to ensure the Company meets customer expectations;
- Moving to cloud solutions where and when appropriate to reduce cost, improve security, and increase the speed of providing new capabilities;
- Treating data as an asset and deploying analytics on a larger scale for effective decision making, optimization of existing assets, and efficient investment prioritization;
- Deployment of a consistent asset management system and integrated control systems to reduce risk, optimize and digitize processes, and monitor the health of the system to identify necessary preventative maintenance that reduces waste and long-term costs;
- Ensuring customer data is safe and secure, their privacy is protected, and both critical technology assets as well as critical infrastructure assets are secure; and
- Managing security risks and mitigating associated threats.

Q. Have there been any changes to the IT functions that are new in Case No. U-21806?

A. Yes. The following changes have been integrated in my direct testimony and exhibits: (1) the Security Department is part of the IT Department and no longer represented by a separate witness; (2) the Company has integrated the analytics function (Analytics and Outreach) that was part of the Customer Interactions function into the IT Department; and (3) the Company has also integrated the analytics function that was a part of the Process, Analytics & Technology function, within Operations Performance, into the IT Department. These changes, new in Case No. U-21806, better centralize the Company's technology expenditures and expenses.

The Security Department capital expenditures and O&M expenses will continue to be represented as a separate business category in testimony and exhibits, while the Analytics expenses and expenditures will be represented in the IT business category for Operations O&M expense and the appropriate business category for capital expenditures and Investments O&M expense.

Q. Please describe the functions the IT Department performs.

A. The IT Department provides secure digital solutions and services to the Company's customers and internal business units. This includes identification, delivery, operational support, and maintenance of both on-premise and cloud software solutions and computing and communications infrastructure and analytics to support customer safety and reliability. The IT Department also provides the day-to-day operational support for coworkers using technology, whether that technology is a desktop, laptop, or mobile device (e.g. ruggedized field device, tablet computer, cell phone, smartphone, or other handheld device).

The scope of the IT Department also includes OT. OT is the set of real-time industrial control systems that monitor and control the Company's critical gas infrastructure, such as the Gas SCADA systems.

Additionally, the scope of the IT Department includes Security. Security exists to deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal effect if or when a threat is successful in causing impact, and comply with all governmental and industry regulations. Security sets standards based on external threats and guides security work required by the IT and OT teams.

Q. How does technology support the Company's gas plans?

A. Technology is an integral part of all aspects of the Company's gas strategy from gas delivery all the way to the customer. The NGDP outlines the need to invest in both IT and OT to provide the following essential digital capabilities that will enable the Company to deliver safe, reliable, and affordable natural gas to customers while transforming the system to deliver cleaner fuels for a decarbonized future. These include: (1) expanding system monitoring to support 24/7 system control; (2) improving data analytics to support asset reliability and identification of optimal utilization of compression and storage assets; (3) modernizing the distribution and transmission system; (4) incorporating predictive and condition-based maintenance; (5) transforming work and asset management; (6) ensuring cyber security of Company assets and complying with security-related regulations; and (7) achieving methane reductions.

This requires investments in new technology, as well as enhancing existing technology assets and processes to keep them operating safely and securely in support of the Gas Safety Management System and increasing regulation which I describe later - specifically in the areas of asset management, work management, system automation and control, security and privacy, and advanced analytics.

The use of technology is also essential to establishing data analysis techniques to understand, communicate, and engage with the Company's customers in a meaningful way; connecting with customers using their channel of choice; enhancing the Company's digital resources in response to growing customer feedback that they prefer "self-service" through digital channels; providing customers accurate, timely energy bills, and consistent payment processes; and offering options for customers to understand their energy consumption.

Q. What are some of the biggest challenges the IT Department currently faces?

A. A big challenge the IT Department currently faces is the integration and implementation of emerging technologies, data, and analytics needed to achieve the Company's goals described in the NGDP. The Company relies heavily on accurate data and high-performing systems that can handle higher transaction and data volumes. Customers depend on these same systems to report gas leaks, receive timely information on consumption, and start or stop service. It is important that the Company achieve full recovery of requested expenses and expenditures to keep these systems updated with the latest security and maintenance patches while delivering new capabilities to help restore customers faster.

Another challenge is that security continues to be a significant risk area and challenge for utilities. Traditional physical security issues of protecting publicly accessible, geographically dispersed critical infrastructure are and will continue to be exacerbated as resources become more distributed. Cyber security concerns include privacy, data breaches, ransomware, ransom extortion, denial of service (an attack meant to shut down a machine or network, making it inaccessible to its intended users), and critical infrastructure attacks. For example, a February 7, 2024 Cybersecurity Advisory from the Cybersecurity and Infrastructure Security Agency ("CISA") states that the CISA, National Security Agency, and Federal Bureau of Investigation assess that People's Republic of China ("PRC") state-sponsored cyber actors are seeking to pre-position themselves on IT networks for disruptive or destructive cyberattacks against U.S. critical infrastructure in the event of a major crisis or conflict with the United States.[1] The U.S. authoring agencies have confirmed that the PRC state-sponsored cyber group known as Volt Typhoon has compromised the IT environments of multiple critical infrastructure organizations - primarily in Communications, Energy, Transportation Systems, and Water and Wastewater Systems Sectors - in the continental and non-continental United States and its territories, including Guam.

While cyber security is no longer a new area, each year impacts from cyber security incidents increase. According to a 2024 Sophos report on the state of ransomware, while the rate of ransomware attacks dropped slightly since 2023, the average payout more than doubled from $1,500,000 in 2023 to $3,900,000 in 2024. In addition to ransomware, data breaches, ballooning the North American Electric Reliability Corporation ("NERC")/ Critical Infrastructure Protection ("CIP") compliance fine maximums, and the federal government warning regarding potential critical infrastructure attacks from Russia or China as part of global geo-political tensions, utility security teams must be prepared with plans that address the need for securing customer data, maintaining compliance, protecting customer privacy, and protecting the critical infrastructure that serves the Company's customers.

Q. Please further explain the current environment with respect to cyber threats facing utility companies.

A. Cyber threats are increasing. The most glaring example is ransomware as discussed above. These threats have increased, not only in their impact but also their level of sophistication. Criminal groups are profiting on ransomware, and it has become such a lucrative business

[1] Available at https://www.sophos.com/en-us/content/state-of-ransomware.

that they now conduct cyberattacks in a more sophisticated manner with teams of people who focus on an individual target. Such groups are more focused on Fortune 500 companies because of the potential for large ransom payments.

The Progress Software "MoveIT" extorsion event demonstrates this increase in sophistication. A zero-day vulnerability (a flaw in a system or device that is unknown and does not have a fix available to correct the flaw, rendering the system vulnerable) was used to compromise the data of hundreds of MoveIT customers across all industries. The ability to exploit zero-day vulnerabilities has historically only been within reach of nation-state actors, not criminal groups. The amount of money being made has allowed these groups to invest in finding such vulnerabilities and dramatically increased their capabilities. The Company sees, on average, several hundred cyber security events daily. This volume demands a robust security program with various layers of defense. No single tool, person, or process can protect the Company's assets 100% of the time; therefore, the Company must rely on multiple lines of defense to meet these challenges.

Beyond ransomware, nation-state actors have a strong interest in United States critical infrastructure. The federal government has repeatedly called out this risk and has been imploring critical infrastructure owners to increase their capabilities. The Biden Administration released a memo titled "National Security Memorandum on Improving Cybersecurity for Critical Infrastructure Control Systems" ("National Security Memo").[2] The implications of the National Security Memo are clear.

First, the threat to critical infrastructure is real and no longer theoretical. Even the Company has seen intrusion attempts from nation-state level actors. The National Security

[2] Available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/07/28/national-security-memorandum-on-improving-cybersecurity-for-critical-infrastructure-control-systems/.

Memo provided that "[t]he cybersecurity threats posed to the systems that control and operate the critical infrastructure on which we all depend are among the most significant and growing issues confronting our Nation."

Second, cyber security of critical infrastructure is a national security issue and priority. The National Security Memo explained that "[t]he degradation, destruction, or malfunction of systems that control this infrastructure could cause significant harm to the national and economic security of the United States." Utilities have had strong cyber security programs, and the Company is no different. However, by calling out cyber security of critical infrastructure as a national security issue, the Biden Administration is signaling that the Company, as an owner of critical infrastructure, needs to meet an even higher standard moving forward. The National Security Memo suggests that utilities need to have capabilities matching those of the top government agencies and contractors. This increased expectation will take time to develop and increased funding to achieve.

Third, as ordered by the Biden Administration, the CISA has established Cross Sector Cybersecurity Performance Goals, which signals the federal government's interest in gaining further assurances that owners and operators of critical infrastructure are meeting the expectations set forth in the memo. The Company expects this to include new, mandatory regulatory standards for natural gas.

Q. Please describe how physical threats are increasing or evolving.

A. Cyber security receives much of the national headlines because it is a relatively new risk and does not require physical proximity to execute an attack. However, physical security risks are still extremely relevant in the critical infrastructure space, and they continue to evolve. In the past year, multiple incidents have occurred at other gas utilities where equipment was broken into and tampered with to the point of impacting gas delivery to customers. One utility reported that in December 2020, three separate gas sites were criminally vandalized, all at the same time, causing service disruption of over 3,500 customers for over three days with no gas during extremely cold temperatures. Furthermore, as gas becomes more of a target for environmental scrutiny, the Company may see more attempts to tamper with gas assets. One such example is an incident at a gas city gate where an individual used a stolen excavator to dig at night and nearly hit a gas line. Potential damage could have included thousands of customers without gas and over $10 million in repair costs.

Q. What physical security challenges are you experiencing in securing critical infrastructure assets?

A. The very nature of certain utility assets makes them very challenging to secure. Large assets such as a headquarters building or power plants can be secured using traditional physical security measures such as video cameras, card access, fencing, locks, keys, gates, and guards. The smaller, more distributed assets are significantly more challenging to secure. Placing guards at each asset would be untenable from a cost perspective. Technology solutions have historically been challenging because of limited feature sets (enhancements and capabilities) and network capacity at many of these remote locations. These limitations have led utilities to implement basic physical protections and accept remaining risk. Responses to security issues in these environments are, therefore, reactive and have become insufficient. These factors have made these critical assets soft targets to those who would do harm intentionally and attractive for opportunistic crimes. A shift to a more proactive approach will minimize the impacts to customers from outage, safety, and cost perspectives.

Based upon recent pilot testing of solutions, there are now technology options capable of meeting these objectives. Where more traditional locks are the only practical option for items such as gates, control houses, and switches, the Company needs appropriate key management and locks made of materials that cannot readily be cut. Proactive approaches such as these will allow the Company to better protect its assets, increase safety, and reduce costs to customers.

Q. What is changing in the regulatory landscape?

A. The industry is expecting additional mandatory cyber security standards across the regulatory landscape. These include national reporting requirements for cyber security incidents and federal privacy legislation like what was enacted in Europe's General Data Protection Regulations, and legislation passed by many US states. There are also bills aimed at ransomware and critical infrastructure protections with various requirements.

On the privacy front, proposed legislation at the state and federal level would, if passed, impact management of customer data, necessitating standing up a formal customer data access, authentication, request, and provisioning program, a dispute resolution body and accompanying processes, as well as staffing for a thorough review, alignment, and continued operation of the Company's Customer Data Privacy Program. The Company continues to monitor the legislative landscape and proactively prepare with the implementation of privacy industry standards.

Q. Has the work required to meet cyber security regulations and requirements increased in recent years?

A. Yes. The current and emerging cyber-attack trends are evolving, and the number of threats is increasing in impact and sophistication as described earlier in my direct testimony.

As the security industry best practices evolve, new regulations are issued, and security requirements change, the IT Department must strive to keep pace with the time and expense of retrofitting existing infrastructure and applications to maintain compliance and an appropriate security posture.

Q. Do cyber security requirements increase the frequency of IT patching and upgrades?

A. Yes. To address changing security threats and vulnerabilities, vendors regularly release security fixes or "patches" to their products. The increased volume of threats to digital assets heightens the need to keep systems current, and timely security patching is a key control for any security program. Technology vendors establish timelines for versions of their product they no longer support or no longer provide security updates or patches for. Where the Company may have had more discretion in the past to defer upgrades, it now must ensure the appropriate upgrade or replacement frequency to meet security requirements. Patching analysis, patch application, and patch tracking activities are all considered Operations O&M expenses. The Company focuses on mitigating exposure to "Known Exploited Vulnerabilities" that the Cybersecurity and Infrastructure Security Agency has confirmed have been used to breach other companies' IT systems in the past. Reducing vulnerabilities requires timely patching, as well as upgrades and replacements to IT software and systems. The operational expenses related to security are important for the protection of Company assets and customer information.

Q. How does the Company prioritize, balance, and manage the delivery of new capabilities that support the NGDP with operational work that includes meeting the security requirements described above?

A. The Company's critical security and operational fixes are given priority over new capabilities to ensure safe, secure, and reliable operation of its digital assets. There is a high demand for new and enhanced technology capabilities across the Company. New investments are prioritized based on an evaluation of the benefits, costs, customer value, and necessity to Company goals through a series of reviews by cross-functional business teams. The highest-ranking projects are approved through the Company's budget and rate case processes and ultimately implemented.

Q. What business categories has the Company defined in the IT Organization?

A. The Company has defined the following business categories in the IT Department supporting the NGDP and customer offerings in this case: (1) Gas; (2) Electric & Gas Shared; (3) Corporate; (4) Customer; (5) IT/Digital Foundation; and (6) Security. These business categories are used to group investment spending in my exhibits to better connect rate case filings with the Company's plans. I will describe each of the business categories later in my testimony.

OPERATIONS O&M EXPENSES—MAINTAIN AND OPERATE EXISTING ASSETS

Q. What is Operations O&M expense for IT?

A. The Company uses Operations O&M expense to provide the required level of operational support, reliability, and security for technology investments; maintenance for security facilities and systems to ensure system reliability, vulnerability assessments, and penetration tests; and fulfillment of all state and federal laws and regulations, perimeter protection, guards, card access, cameras, executive protection, and investigative services. Operations O&M expenses include fixed and variable ongoing costs. Fixed costs include software vendor maintenance agreements, cloud subscription contracts, annual license contracts, and application or appliance support through managed services contracts. Software and cloud solution vendors typically increase these fixed costs on an annual basis. Variable costs include labor for equipment monitoring, break/fix activity, maintenance activity, disaster recovery, security improvements, software patching, and cloud usage costs. Operations costs also include physical security site assessments, vulnerability and penetration test remediation, additional guard support, system break/fix or maintenance activity, privacy program maturity, staffing support to meet emerging regulatory laws and regulations, and additional security system improvements. The activities associated with the fixed and variable costs are required to keep the Company's digital, information, and physical assets protected and performing at sufficient levels. The Company's customers benefit from the system stability and reliability that result from the activities funded by IT Operations O&M expense. These activities include emergency response, 24/7 billing, payment and usage services, contact center support, new service installations, and various other digital offerings, as well as physical and cyber security activities. Any unrecovered Operations O&M cannot be recovered in future rate case filings, which is why any disallowance could impede the Company's ability to maintain and secure its facilities and systems.

Q. Please describe the operational work required to keep information and physical assets protected from cyber threats.

A. There is a variety of operational work required to keep information and physical assets protected from cyber threats. First, regarding information assets, security tools must be kept functional when they are called on to protect the technology vital to serving the Company's customers. This technology includes software to collect logs, scan for vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second, IT resiliency must be kept up to date ensuring backup data and redundant infrastructure are in place in the event of a cyber intrusion. Third, as described previously, systems must be patched on a regular basis in accordance with security requirements. Vendors regularly release security updates that must be tested to ensure these updates do not introduce negative impacts to Company-specific configurations when deployed. Fourth, as cyber security standards and requirements change, IT teams must implement the appropriate corresponding technical changes on existing systems to ensure Company assets remain secure. These requirements evolve and adapt as threats change in our environment. Security regularly reviews and updates physical and cyber security standards to maintain the appropriate posture with various industry frameworks, as well as compliance with cyber security regulations. This includes the technical requirements for IT to follow, which increases operational costs while continuing to best protect Company assets

Regarding physical assets and employee safety, first, routine assessments must be performed on all assets and facilities to ensure proper maintenance is performed and security protections are properly placed including perimeter protection, cameras, and card readers for facility access. Second, additional security support is needed for employees when threats are present near field project work, storm restoration activities, or Company sponsored public events or forums. Third, additional security guard support is needed at facilities on an ad hoc basis (based on intelligence collected from facilities or crews, threats of violence against the Company, increased protest activity as seen in 2020, increased contractor traffic, and potential employee issues) to ensure the safety of employees and any visitors to the Company's facilities.

Q. What value will customers receive for the projected test year O&M expenses?

A. Customers are required to provide certain types of data as part of the service provided to them and want to know that the Company has a world class cyber security program working to protect data provided. Data breaches can cause identity theft, fraudulent charges, and time lost addressing related associated impacts. Beyond data breaches, customers also expect their data to be handled properly and only for the purposes intended. The discipline which addresses these concerns is broadly referred to as privacy, which is also within the corporate responsibility of the IT Department. In addition to data-related concerns, customers expect the Company's core services to be available 24/7. This is relevant on both the corporate and operational sides of the business. A ransomware attack would limit the service the Company can provide to customers and could lead to delays in resolving issues, obtaining service, outages, or significant safety concerns. An attack against the Company's operational systems could lead to a protracted loss of electricity or natural gas service for large portions of the service territory. Interruption of gas or electric service due to a cyberattack is not acceptable, and customers expect the utility to have all the protections necessary to ensure this does not occur.

Q. Please describe Exhibit A-17 (SHB-1).

A. Exhibit A-17 (SHB-1) is a Summary of Actual and Projected IT Operations O&M Expense for the Years 2023, 2024, 2025, and 12 months ending October 31, 2026. Page 1 summarizes the gas allocation of actual and projected IT Department operational expenses. Specifically:

- Column (a) provides the Operations O&M expense category;
- Column (b) identifies the total 2023 historical Operations O&M expense as $28,338,000;
- Column (c) identifies the total 2024 projected Operations O&M expense as $31,222,000;
- Column (d) identifies the total 2025 projected Operations O&M expense as $35,328,000;
- Column (e) identifies the total projected Operations O&M expense for the 2 months ending December 31, 2025 as $5,888,000;
- Column (f) identifies the total projected Operations O&M expense for the 10 months ending October 31, 2026 as $30,870,000;
- Column (g) identifies the total projected Operations O&M expense for the Test Year as $36,758,000; and
- "Labor" line items include employee labor, "Contracts" line items include hardware and software licenses and maintenance, and software subscriptions, "Material" line items include individual computer peripherals, tools, supplies, and replacements for failed components such as hard drives; and "Contractor" line items include staff augmentation, the Company's managed services contracts, and other contracted services. "Non-Labor Other" line items include employee training, wireless plans, and supplies.

Page 2 presents the amounts of the projected Operations O&M expenses that were developed by applying an inflation rate to the historical O&M expense. Specifically:

- Column (a) describes the categorical expense;
- Column (b) provides the historical Operations O&M expense;
- Column (c) provides the historical amount that an inflation rate was applied to;

- Columns (d), (f), and (h) provide the inflation increases for each respective period;
- Columns (e) and (g) provide the amount that an inflation rate was applied for 2024 and 2025, respectively;
- Column (i) includes amounts that were projected using other methods; and
- Column (j) provides the projected test year Operations O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please describe the Other Adjustments in Exhibit A-17 (SHB-1), page 2, column (i).

A. IT does not apply inflation in all categorical spend projections for Operations O&M expense. Labor is the only categorical spend projection that includes a merit increase based on the inflation rate. Inflation is not used to project any other categorical spend projections for Operations O&M expense. Future contract expenses reflect current commitments to increase payments under existing contracts, as well as the addition of new contracts needed for ongoing and new project work taking place before or during the test year. Material and Non-labor Other are projected based on historical spend and known adjustments for employee training needs, wireless plans, and supplies.

Q. Please describe the projected IT Department Operations O&M expense for 2023 and 2024, as reflected in Exhibit A-17 (SHB-1).

A. The Operations O&M expense in 2024 of $31,222,000 is projected to be an increase over 2023, which is $26,062,000 for IT and $5,160,000 for Security. The reason for the increase in 2024 is the result of organizational changes and the necessity to fund continued investment in programs to sustain and improve system reliability; to maintain, improve, and secure critical enterprise systems that support the Company's NGDP; and to prevent obsolescence and risk to business operations offset by cost-saving measures. Key drivers for the change from 2023 to 2024 for IT include: (1) net labor is reduced based on resource reductions and move of network resources to Security ($1.0 million) offset by merit increases ($0.2 million), and transfer of website from Customer Operations and analytics resources from Customer Interactions and Operations Performance ($0.4 million); (2) net decrease in material and Non-Labor Other ($0.02 million); (3) increase in contractor ($0.95 million), which a portion ($0.45 million) is based on the transfer of website contractors costs from Customer Interactions; and (4) net increase in contracts for cloud subscriptions and license and maintenance agreements due to cost optimization efforts offset by annual increases ($1.23 million).

Key drivers for the change from 2023 to 2024 for Security include: (1) labor increased based on merit increases ($0.05 million) and increase for resources to support the Fusion Center and move of network resources from IT ($0.76 million); (2) net increase in contracts for cloud subscriptions and license and maintenance agreements ($.56 million) including reductions in MS Azure costs offset by an increase in cloud security platform; (3) net decrease in contractor ($0.37 million) based on reduction in Physical Security contractors; and (4) net increase in Non-Labor Other ($0.15 million) based on increase in training and business expense related to increase in resources.

Q. Please describe the projected IT Department Operations O&M expense for 2025, as reflected in Exhibit A-17 (SHB-1).

A. The Operations O&M expense in 2025 of $35,328,000 is projected to be an increase over 2024, which is $28,503,000 for IT and $6,825,000 for Security. The reason the Company is projecting an increase in 2025 is the necessity to fund continued investment in programs to sustain and improve customer reliability as the Company continues investing to maintain, improve, and secure critical enterprise systems and migrate applications to the cloud. Known increases that are projected for IT include: (1) merit increase ($0.14 million) and backfill of resources supporting analytics ($0.59 million); (2) increase in cloud subscriptions and license and maintenance agreements ($1.5 million), including increase in support costs related to the Digital-Cloud Data and Analytics Platform project; (3) increase in material costs ($0.06 million) for circuits; and (4) increase in contractor costs ($0.17 million).

Key drivers for the change from 2024 to 2025 for Security include: (1) labor increase based on merit increases ($0.06 million) and increase for resources to support physical and cyber security ($0.37 million); (2) net increase in contracts for cloud subscriptions and license and maintenance agreements ($0.7 million); (3) net increase in contractor ($0.53 million) based on physical security contract resources; and (4) net decrease in Non-Labor Other ($0.01 million) based on projected training and business expense.

Q. Please describe the projected IT Department Operations O&M expense for the test year, as reflected in Exhibit A-17 (SHB-1).

A. The Operations O&M expense in the test year of $36,758,000 is projected to be an increase over 2025, which is $29,933,000 for IT and $6,825,000 for Security. The reason the Company is projecting an increase in the test year is the necessity to fund continued investment in programs to sustain and improve customer reliability as the Company continues investing to maintain, improve, and secure critical enterprise systems and migrate applications to the cloud. Known increases that are projected for IT include: (1) merit increase ($0.13 million) and (2) increase in cloud subscriptions and license and maintenance agreements ($1.4 million), including costs related to the Genesys Cloud

Migration, Standard Work Plan, and Digital-Hybrid Cloud and Data Center Migration projects.

Key drivers for the change from 2025 to the test year for Security include: (1) labor increase based on merit increases ($0.05 million) offset by resources efficiencies and (2) no change in contracts for cloud subscriptions and license and maintenance agreements due to planned cost optimization efforts to offset increases.

Q. What does the Company's IT Operations O&M expense include?

A. As described earlier, Operations O&M expense is made up of several components, such as labor, business expenses, material costs, contractor support, and vendor licensing and maintenance contracts.

"Labor" includes operational and governance costs for the IT employees who perform activities such as maintaining and supporting capital assets; disaster recovery and business continuity planning and testing; cyber security analysis and mitigation, such as security patching; and implementing performance measures to control IT costs and ensure compliance. These activities are variable and dependent on the outcome of risk analyses and other factors.

"Non-Labor Other" includes costs such as: business expense, employee training, wireless plans, and supplies. These costs are variable and dependent on needs of the organization.

"Material" includes costs such as individual computer peripherals, tools, supplies, and replacing failed components such as hard drives. These costs are variable and dependent on needs of the organization.

"Contractor" are costs of managed services and third parties that maintain and operate the Company's IT assets. Very similar to "Labor," the activities include system monitoring, system break/fix, disaster recovery activities, system analysis, and patching. The use of third parties to maintain and operate the Company's IT assets provides value by helping to control labor costs, offering up to 24/7/365 support, and providing increased access to specialized IT expertise.

Contracts, including "On-Premise Contracts" and "Cloud Subscriptions," reflect the Company's IT operations expenses for contracts with vendors who provide software and hardware licensing, support, and maintenance services so systems remain safe from mechanical and software failures and cyber intrusions. Lapses in licensing, support, or maintenance coverage caused by financial constraints would expose the Company to unfavorable security and operational risks or issues.

The Company relies heavily on vendors and their products to run the utility's digital systems and, as a result, the number of contracts and the corresponding costs are a significant piece of the total Operations costs.

Q. Please explain why the Company is proposing to use more cloud/Software as a Service ("SaaS") based products.

A. Cloud/SaaS based offerings are often the only option for certain technology services/vendors. For those that do also have on-premise options, many are stating that they will not be updated as quickly or may lack certain capabilities of their cloud counterparts. Vendors are making this shift for many reasons. First, as technology moves more and more to the cloud, security services need to adapt as well. Second, vendors can much more quickly build new capabilities for customers in a cloud-based scenario where they control all the underlying hardware and infrastructure. Finally, the massive scale of security data requires much more flexibility which the cloud offers, and on-premise does not.

In addition to the industry drivers, there are benefits to both the Company and customers. More SaaS means fewer large capital outlays for large hardware purchases, vendor integrations, and less asset refresh cost. The Company anticipates fewer large capital projects in its future year planning for cyber security as capital requests have reduced, while physical security requests are increasing. Finally, using SaaS allows the Company to receive the best security capability available and allows vendors to adapt to changes much more quickly than on-premise solutions.

Q. Please explain why the Company is proposing increased costs for third-party assessments and consultants.

A. As scrutiny increases, Security Department teams have an increased need for third-party validation to both ensure appropriate security controls are in place, but also to inform various stakeholder groups. Outside expertise is also critical to ensure internal teams see broader perspectives and understand leading practices. The dollars requested will be used in a variety of ways including external penetration testing, maturity assessments, incident exercises, research, coaching, and consulting.

Q. Is the method used by the Company to project IT Operations O&M an accurate and prudent approach?

A. Yes, the method used by the Company to project IT Operations O&M expenses in Exhibit A-17 (SHB-1) is the most accurate method. The Company's approach uses a detailed analysis of known fixed and variable expenses for the test year. These include increases that result from new investments and assets tied to growth in digital, new cyber security regulations and requirements, and outcomes of cost optimization efforts. By using known and expected expenses that are coupled with the evolving digital landscape, the projection is the best representation of the Company's required IT Operations O&M expenses in the test year.

Q. Please describe Exhibit A-18 (SHB-2).

A. Exhibit A-18 (SHB-2) is the IT Cloud Computing Prepaid Balance for Gas and Common operations for the historical 13 months ending June 30, 2024 and the projected 13 months ending October 31, 2026. It provides a summary of the gas allocation of actual and projected IT Department operational expenditures. Specifically:

- Column (a) provides the prepaid balance category;
- Columns (b) through (n) provide each month's ending IT cloud computing prepaid balance; and
- Column (o) provides the 13-month average of columns (b) through (n).

Q. Please describe the purpose of Exhibit A-18 (SHB-2).

A. The move to utilize cloud computing is resulting in an increase in prepaids associated with cloud computing subscriptions and implementation costs. The Company has identified cloud computing as a viable alternative for several technology solutions, which are described in more detail for the associated projects below. To support the adoption of cloud computing, the Company is adjusting working capital to reflect projections for cloud computing subscriptions and implementation costs. Cloud computing costs are projected based on existing cloud computing subscription agreements plus projected new cloud computing costs based on planned implementations. This working capital adjustment is provided by Company witness Heather L. Rayl on Exhibit A-12 (HLR-34), Schedule B-4.

INVESTMENTS O&M EXPENSES—MAINTAIN A CURRENT SYSTEM AND BUILD NEW CAPABILITIES

Q. How is Investments O&M for IT used by the Company?

A. Investments O&M is used by the Company to fund the O&M portion of upgrade projects, asset refresh projects, and technology investments that are needed to provide the new capabilities for internal business units, security operations, and customers.

Q. Please describe the importance of upgrading IT systems for cyber security requirements and operational stability.

A. Upgrading applications, appliances, operating systems, database management systems, and security devices, such as cameras and card readers, are essential to delivering safe, reliable, and affordable gas to the Company's customers. Implementing current versions of technology enables the Company to operate secure and stable systems, remediate security vulnerabilities, keep customer and company data secure, maintain vendor support, address defects that impair stability and functionality, and address version interdependencies and compatibility between systems.

Q. What cyber security risks could occur if the Company does not keep its systems upgraded?

A. Technologies and security devices that are not upgraded are often no longer supported by vendors, which increases security risk as well as system operations risk, as security patches are regularly released by vendors based on known vulnerabilities. Security patches are typically not produced for products no longer supported by the vendor, referred to as end-of-life products; therefore, an end-of-life product may have known vulnerabilities and no method to remediate the risk. This increases the risk of a significant cyber event impacting Company operations, data, and services to its customers.

Q. How does the Company determine which systems need to be upgraded?

A. While the Company's preferred upgrade strategy is to stay, at most, one version behind the vendor's currently available version, the Company considers multiple factors to determine when upgrades are needed. These include application criticality to business and customer operations, severity of existing vulnerabilities and operational risk, operational impacts of performing the upgrade, ability to defer, resource availability, organizational change impact, and cost. Deferring an application upgrade for too long has the potential to increase the overall cost of the upgrade since the larger number of differences between versions generally adds complexity and cost to an upgrade effort.

Until recently, the Company has lacked funds to maintain and keep systems current. This led to technical obsolescence, and the Company is in a position of playing catch-up, adding risk that a significant cyber security or technical issue might not be remediated or mitigated, which would cause direct impact to Company operations, its customers, or both. The Company prioritizes operational support over new investments when resources are limited, thus putting the NGDP at risk when important systems cannot be kept current with available resources.

Q. Please describe Exhibit A-19 (SHB-3).

A. Exhibit A-19 (SHB-3) is a Summary of Actual and Projected IT Investments O&M Expenses for the Years 2023, 2024, 2025, and the 12 months ending October 31, 2026. Page 1 provides a summary of the gas allocation of actual and projected IT Department Investments O&M expenditures. Specifically:

- Column (a) provides the Investments O&M expense category;
- Column (b) identifies the 2023 historical Investments O&M expense as $4,912,000;

- Column (c) identifies the 2024 projected Investments O&M expense as $6,315,000;

- Column (d) identifies the 2025 projected Investments O&M expense as $10,019,000;

- Column (e) identifies the 2 months ending December 31, 2025 projected Investments O&M expense as $3,200,000;

- Column (f) identifies the 10 months ending October 31, 2026 projected Investments O&M expense as $14,748,000;

- Column (g) identifies the Test Year projected Investments O&M expense as $17,948,000;

- For Investments Planning expense, "Labor" line items include employee labor, and "Contracts" line items include hardware and software licenses and maintenance, staff augmentation, and other contracted services; and

- For Investments expense, "Labor" line items include employee labor, "Software" line items include software licenses and maintenance contracts, "Material" line items include hardware purchases and maintenance contracts, "Contractor Costs" line items include staff augmentation, managed services, and other contracted services, "Non-Labor Overhead" line items include overheads, and "Non-Labor Others" line items include pension expense, administrative/general expense, Allowance for Funds Used During Construction ("AFUDC"), and business expenses.

Page 2 presents the amounts of the projected Investments O&M expenses that were developed by applying an inflation rate to historical O&M expense. Specifically:

- Column (a) is a description of the categorical expense;

- Column (b) provides the historical Investments O&M expense;

- Column (c) provides the historical amount that an inflation rate was applied to;

- Columns (d), (f), and (h) provide the inflation increases for each respective period;

- Columns (e) and (g) provide the amount that an inflation rate was applied for 2024 and 2025, respectively;

- Column (i) includes amounts that were projected using other methods; and

- Column (j) provides the projected test year Investments O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please describe the Other Adjustments indicated in Exhibit A-19 (SHB-3), page 2.

A. IT does not apply inflation for categorical spend projections for Investments Planning expense. The investments planning projection is adjusted by $77,000 for an anticipated decrease in the test year for investments planning activities that directly support business case development and cost estimate refinement for projects that support the NGDP, and other Company long-term plans. Inflation is also not used to project future Investments O&M expense. The other adjustments for Investments O&M expense of $13,113,000 are based solely on expected project costs for the test year as compared to the historical period, as detailed later in my testimony and in Confidential Exhibit A-20 (SHB-5).

Q. Are the preliminary project stage activities that must be part of Investments O&M expense per Financial Accounting Standards Board ("FASB") guidelines important in technology investment projects?

A. Yes. The preliminary project stage activities are essential to ensure the Company makes prudent investments in technology that benefit customers. The activities cover much of the work included in the Company's investment planning for IT projects. Investment planning activities gather information that is required by the MPSC in Case No. U-18238 as part of the rate case filing requirements for IT and OT.

Q. Is the investment planning activity speculative?

A. No, it is not speculative. Investment planning is a pragmatic process that results in documented technology investment details. The process documentation includes: a project description and description of system functionality, project timelines including expected implementation date and spending plans, project benefits, a description of alternatives considered and rationale behind the decision, and cost benefit ratio, which were required by the MPSC in Case No. U-18238. Other important activities of investment planning are: identifying high-level business requirements, determining whether the functionality needed is already present in the Company's IT environment, identifying performance and security requirements, working with software vendors and cloud solution providers to demonstrate the effectiveness and security of their products and services, and developing the business case with project costs and benefits to confirm whether a proposed project should be approved for development and implementation.

During this phase, the Company spends the necessary time on up-front planning and due diligence for the technology investment. As an example, to maintain the reliability and safety of the Company's field dispatch communications, the Company needed to replace the aging core radio system infrastructure. The Company spent time on up-front planning for the 800 MHz Modernization upgrade project to build and confirm the scope, estimates, and alternatives. Investment planning is time needed to better understand the vendor solution and organize the work. Investment planning is based on key outcomes and fact-gathering to ensure it is not merely speculative.

Q. Should the Company be allowed recovery for the planning expense tied to technology investments?

A. Yes, the Company should be allowed recovery for this up-front planning activity. This work is required by the MPSC for technology investment, and for good reason. It is in the best interest of the Company's customers that the Company perform these investment planning activities to ensure potential investments provide sufficient value to justify the expense. The Company considers many ideas, but not all are feasible or even warrant investment planning. Critical as these expenses are, the Company does strive to minimize planning expenses; only those potential investments with the highest expected value even reach the planning phase. This reasonable and prudent work has associated costs and is required by the MPSC for technology investment planning. Accordingly, the Company should receive recovery for this required expense.

Q. Would it be more accurate to use a different method to project the Company's IT Investments O&M expenses?

A. No. The level of IT Investments O&M expense is closely coupled with the projected capital expenditures for IT and the upgrade and replacement cycles for existing assets. To fully and appropriately execute plans to spend the capital that has been deemed prudent to deliver value to its customers, keep its technology assets as current and secure as reasonably possible, and adhere to the FASB ASC 350-40 guideline for project activities that should be expensed, the Company requires the specific and forward-looking IT Investments O&M requested for the Test Year period. Other methods such as a historical average, which would be lower than the requested amount in this case, would not allow the Company to keep its systems current for security and reliability and make necessary and prudent capital expenditures to achieve the outcomes of the NGDP and improve customer service. Additionally, the Company projects an increase in cloud solutions, which often have a higher level of Investments O&M than projects in earlier years.

<u>INVESTMENTS CAPITAL EXPENDITURES</u>

Q. Please describe the capital expenditures shown on Exhibit A-12 (SHB-4), Schedule B-5.1.

A. Exhibit A-12 (SHB-4), Schedule B-5.1, identifies the gas allocation of actual and projected capital expenditures to procure, install, and implement the software and infrastructure described in my testimony to meet business requirements. Specifically:

- Column (a) provides the business category designation for the capital expenditures:
  - Corporate;
  - Customer;
  - Electric & Gas Shared;
  - Gas;
  - IT/Digital Foundation; and
  - Security.
- Page 1 of 2
  - Column (b) identifies the 2023 historical year capital expenditures as $27,620,000;
  - Column (c) identifies the 12 months ending December 31, 2024 projected bridge year capital expenditures as $32,046,000;
  - Column (d) identifies the 10 months ending October 31, 2025 projected bridge year capital expenditures as $28,724,000;
  - Column (e) identifies the 22 months ending October 31, 2025 projected bridge year capital expenditures as $60,770,000; and
  - Column (f) identifies the 12 months ending October 31, 2026 projected test year capital expenditures of $50,963,000.
- Page 2 of 2
  - Column (b) identifies the 10 months ending October 31, 2024 capital expenditures as $27,910,000;

  - Column (c) identifies the 12 months ending October 31, 2025 capital expenditures as $32,860,000;
  - Column (d) identifies the 12 months ending October 31, 2026 projected bridge year capital expenditures as $50,693,000; and
  - Column (e) identifies the 34 months ending October 31, 2026 projected bridge year capital expenditures as $111,464,000.

- For Investments expenditures, "Labor" line items include employee labor, "Software" line items include software licenses and maintenance contracts, "Material" line items include hardware purchases and maintenance contracts, "Contractor" line items include staff augmentation, managed services, and other contracted services, "Non-Labor Overhead" line items include overheads, and "Non-Labor Others" line items include pension expense, administrative/general expense, AFUDC, and business expenses.

Q. Please explain Confidential Exhibit A-20 (SHB-5).

A. Confidential Exhibit A-20 (SHB-5) identifies the gas allocation of projected capital and O&M expenditures to procure, install, and implement the software and infrastructure requested in my testimony to meet business requirements. Both O&M and capital are required to complete the projects included in the test year. This exhibit provides details regarding all projects included in this rate case filing for the IT Department. Specifically, within this exhibit:

- Column (a) provides the year of spending for this line item project;
- Column (b) identifies the project name associated with each line item capital expenditure for the applicable year;
- Column (c) identifies the Federal Energy Regulatory Commission ("FERC") category relative to the line item project's asset type;
- Column (d) identifies the Business Category of the project;
- Column (e) provides a synopsis of the project, including the project description and information on project scope, functionality, and benefits;
- Column (f) identifies the project's start date;
- Column (g) identifies the project's end date;

- Column (h) provides the project's cost/benefit ratio;
- Column (i) provides the total Company expected project capital costs;
- Column (j) provides the total Company expected projected O&M costs;
- Column (k) identifies the project's estimate type;
- Column (l) provides the project's gas portion total capital expenditure for the applicable year;
- Columns (m) through (r) provide the details of categorical spend that sum to the total line item Project Capital Spend for the applicable year broken down by:
  - Software costs (m);
  - Material costs (n);
  - Labor costs (o);
  - Contractor costs (p);
  - Non-Labor Overhead costs (q); and
  - Non-Labor Other costs (r).
- Column (s) provides the project's gas portion total O&M spend for the applicable year; and
- Columns (t) through (y) provide the details of categorical spend that sum to the total line item Project O&M Spend for the applicable year by the following categories:
  - Software costs (t);
  - Material costs (u);
  - Labor costs (v);
  - Contractor costs (w);
  - Non-Labor Overhead costs (x); and
  - Non-Labor Other costs (y).

Q. Please explain the difference between Exhibit A-12 (SHB-4), Schedule B-5.1, and Confidential Exhibit A-20 (SHB-5).

A. Exhibit A-12 (SHB-4), Schedule B-5.1, and Confidential Exhibit A-20 (SHB-5) are both capital expenditure exhibits that display different views to address the different requirements of the MPSC, as well as the IT Department, as outlined below:

- Exhibit A-12 (SHB-4), Schedule B-5.1, is a high-level summary of capital expenditures by year, by business category or product line, and by categorical spend; and
- Confidential Exhibit A-20 (SHB-5) is a more comprehensive exhibit displaying the detail of each project over the four-year time periods of 2023, 2024, 2025, and 2026.

Q. Please explain Confidential Exhibit A-21 (SHB-6).

A. Confidential Exhibit A-21 (SHB-6) is an Executive Summary report generated from the Company's internal BPS. This exhibit provides the approved business case information for each IT project in Confidential Exhibit A-20 (SHB-5). Exhibit A-12 (SHB-4), Schedule B-5.1, addresses the Commission's interest in:

- projects having approved business cases;
- total project cost for multi-year projects;
- associated hard savings; and
- benefit-cost overall value utilized by the Company.

This exhibit provides the same view the Company uses internally to review the Executive Summary of each business case approved to be included in the test year. It also outlines the total Company cost of ownership of each project, including the initial one-time project investment which could fund work occurring over multiple years, and the projected ongoing support costs after project implementation. Additionally, it identifies recurring hard savings over the life of the investment and provides the cost benefit ratio with a zero breakeven point calculated by the Company's internal BPS. Specifically, within each section of this exhibit:

- Header Information section includes project name, the date the report was generated, and BPS identification number. Specifically:
  - Project Name is the name of the project that indicates the project objective;
  - Report Pulled is the date the Executive Summary report was generated from BPS; and
  - Item ID is the unique identifier from BPS.
- Basic Information section includes work category, work type, alias, brief description, portfolio, organization, business unit, and department. Specifically:
  - Work Category identifies classification of work and activities based on the Company methodology;
  - Work Type identifies "project" as the type of work for all IT investments;
  - Alias identifies historical project names for reference;
  - Description identifies a brief description of the project's intent and the expected outcome;
  - Portfolio identifies the financial planning portfolio for whom the work will be performed;
  - Org identifies the financial planning organization for whom the work will be budgeted;
  - Business Unit identifies the business unit for whom the work will be budgeted; and
  - Dept identifies the department for whom the work will be budgeted.
- Work Objectives includes a synopsis of the project, including the problem statement, objectives, information on project scope, functionality, and benefits, and alternatives considered. Specifically:

- Problem Statement provides an explanation of the problem(s) the work addresses;
- Objectives provides information about the business value the project will deliver;
- Scope describes the high-level business functionality and a list of high-level project deliverables; and
- Alternatives provide a summary of each of the alternatives considered, why each alternative was not selected and the rationale behind the alternative selected.

- Dates section includes the projected implementation phase start or end dates for projects, with the exception of the Annual Spend Programs such as Asset Refresh Programs, Application Currency, and Enhancements. Specifically:
  - Initiation is the start date of the project Plan phase;
  - Project Plan & Scope Definition is the end date of the project Plan phase;
  - Final Engineering, Planning & Design is the end date of the Design phase;
  - Execution is the end date of the Execute phase;
  - In-Service/Go-Live is the project's implementation date; and
  - Closeout is the end date of the Close phase.
- Funding Summary section includes a Total Company summary and detailed breakdown of projected categorical spend by year for each project. Specifically:
  - Summary of the Total Cost of Ownership of projected capital expenditures and O&M expense for each project, including ongoing maintenance, where:
    - Cap+COR is the total of all the capital expenditures; and
    - O&M is the total of all the O&M expense for the project implementation and ongoing maintenance.
  - Total Project Cost contains a detailed categorical breakdown for projected capital expenditures and O&M expense for each project, excluding ongoing maintenance, where:
    - Labor includes the internal staffing costs for project implementation;

- Outside Services includes the external labor and services for project implementation;
- Business Expenses/Overheads includes costs for items such as training, travel, lodging, and meals and Loadings & Allocations for Corporate Overheads and AFUDC;
- Employee Benefits includes costs for employee benefits;
- Material includes costs for hardware purchases;
- Licenses, Permits & Fees includes costs for software and hardware licenses and maintenance; and
- Other includes miscellaneous costs.

- Value & Impacts Summary Section provides a summary of the projected cost and benefits, risk and other value associated with a project for Capital expenditures and O&M expense, including ongoing maintenance, where:
  - For purposes of O&M:
    - Reduction includes the hard O&M savings;
    - Initial includes the implementation and ongoing maintenance costs;
    - Incremental includes any other O&M costs; and
    - Net is the difference of the reduction, initial, and incremental O&M costs.
  - For purposes of Cap+COR:
    - Reduction includes any hard capital savings;
    - Initial includes the implementation costs;
    - Incremental includes any other capital costs; and
    - Net is the difference of the reduction, initial, and incremental capital costs.
  - For purposes of Revenue:
    - Reduction includes any expenses;
    - Initial includes implementation revenue;

    - Incremental includes any increase in revenue; and
    - Net is the difference of the reduction, initial, and incremental revenue.
- For purposes of determining financial value of a project, the B/C Ratio (Overall), as shown in the figure below, is the net present value of the change in O&M, plus change in Capital, plus change in Revenue, divided by Total Cost of Ownership set with a breakeven point at zero.

$$\textit{Financial Value}\ (F_{Overall}) = \frac{\sum B}{\sum C} - 1$$

Where
B = Benefits
C = Total Costs

- For purposes of identifying risk:
    - Type of Corporate Risk;
    - Level of impact;
    - Likelihood of risk; and
    - Description of risk.
- And, for purposes of identifying other value:
    - Type of other value; and
    - Description of other value.

Q. Please explain the breakeven point for the Company's B/C Ratio (Overall).

A. Using the Company's internal BPS B/C Ratio (Overall), the breakeven point is equal to zero where financial benefits and total costs are equal. If the result of the calculation is greater than zero, financial benefits exceed costs. If the result is less than zero, total cost of ownership exceeds the financial benefit.

Q. Does the cost summary component in the Company's B/C Ratio (Overall) use the total one-time project cost, or the total one-time project cost plus the ongoing support costs?

A. The Company's internal BPS B/C Ratio (Overall) cost summary denominator uses total one-time project cost plus the ongoing support costs.

Q. Where is the total Company project cost number distinguished from the total Company project cost number that includes ongoing maintenance cost?

A. The total one-time Company project cost is the Total Project Cost at the bottom right corner of the Funding Summary Section of Confidential Exhibit A-21 (SHB-6). This section of the Funding Summary section, starting with Labor, lists the breakdown of different cost categories for this investment. The total projected Company cost of ownership, including annual ongoing support costs, is the Total Cost of Ownership value on the right of the Funding Summary Section.

INVESTMENT IDENTIFICATION, PRIORITIZATION, APPROVAL, AND PROJECT PLANNING

Q. Please describe how technology projects are initiated, prioritized, and approved within the Company.

A. The initiation of a technology project begins with identification of a need for new or updated technology to meet the requirements of the Company's customers, including technology that customers interact with directly, and technology that sustains and improves reliability in service of customers. For example, IT collaborated closely with Company witnesses and representatives from the gas departments to identify technology projects and foundational digital investments necessary to enable the NGDP. The joint teams prepared business cases for each of the projects utilizing standard format and content.

After sponsor approval, individual projects are prioritized based on an evaluation of the benefits, costs, customer value, and necessity to Company goals through a series of reviews by cross-functional business teams. The highest-ranking projects within the level of IT funding approved through the Company's budget and rate case process are selected for implementation and approved by each business area, followed by approval of the overall IT budget by the senior officer team. Due to the rapid pace of technology change and quickly changing business conditions, emergent projects are identified and vetted through IT and the affected internal business areas throughout the year as business objectives, Company goals, and customer needs and expectations evolve.

Q. Please explain how IT's investment forecasts evolve over the course of project planning and implementation.

A. IT's investment forecasts begin with a ROM estimate. The Company uses the term "ROM" to characterize an initial estimate that includes research, analysis, and a business case. ROM estimates are typically determined by technology and subject matter experts inside and outside the Company in comparison to historical actual costs for similar projects. The purpose of the ROM estimate is to determine whether the estimated costs justify the value provided by the new capabilities without spending an inordinate amount of investment planning O&M developing the bottom-up estimate. From that point, investment forecasting depends on the method used to deliver the intended solution. In the case of Agile delivery, the project team targets the delivery of the highest business value capabilities within the projected funding. In the case of traditional waterfall delivery, once the formal design of a project has concluded, IT subject matter experts perform a detailed definitive estimate for execution. Factors may arise during project execution, such as resource needs, delays in receiving materials, changes in project schedule that shift spending between years, and changes in project scope or complexity that results in funding needs being lower or higher than initially estimated through the ROM process.

Q. Do the Company's total IT capital projections reflect a 20% reduction for those projects whose projections are based on a ROM?

A. Yes. Despite ROM cost-cutting concerns, the total capital projections include a 20% reduction for those projects whose projections are based on a ROM. In order to prevent over recovery, a 20% ROM adjustment is calculated by Business Category for those projects with a ROM estimate with the expectation that the full costs of approved projects may be recovered in a future rate case. These reductions are included in the table below and further reflected in Confidential Exhibit A-20 (SHB-5). Additionally, the ROM Adjusted Test Year Capital is identified for each project later in my testimony.

Year	Projected	Adjusted Projected (20% ROM Adjustment)
2023	$27,620,499	$27,620,499
2024	$32,101,841	$32,046,466
2025	$41,044,512	$38,330,711
2026	$57,459,318	$49,303,979
Test Year	$57,941,869	$50,693,453

Q. Was this 20% reduction to capital expenditures for all ROM estimate projects a reaction to the Commission's decision on page 128 of its December 22, 2021 Order in Case No. U-20963?

A. Yes, in Case No. U-20963, MPSC Staff ("Staff") recommended a 20% disallowance for ROM estimates (Case No. U-20963, 6 TR 4081), and the Commission agreed saying that the ROM estimates are akin to contingency costs. The 20% reduction to capital expenditures for all ROM estimate projects used by IT in this case differentiates the

Company's ROM estimates from the ROM estimates it used in Case No. U-20963 (in fact, the 20% reduction reflects Staff's position in Case No. U-20963) and further shows that the ROM estimate projects do not include contingency. Contingency is a project management best practice to add and reserve a percentage of a project's budget for unforeseen circumstances encountered during the course of the project. Due to previous disallowances, IT estimates do not include contingency. The ROM estimate is (1) intended to cover the full cost of the project rather than a portion, (2) built to address specific scope rather than unforeseen events, and (3) is calculated by technology and subject matter experts for a specific project whereas contingency is a percentage allocation based on an industry percentage value and/or project risk rating.

Q. Which exhibits contain the estimate breakdown for each project?

A. Confidential Exhibit A-20 (SHB-5) contains each project's gas allocation spend for the applicable year broken down by software, materials, labor, contractor costs, and non-labor overhead and non-labor other costs. Confidential Exhibit A-21 (SHB-6) contains Company spend for each project in the historical, bridge, and test years, broken down by year, that shows:

- Staffing;
- Outside Services;
- Business Expenses/Other;
- Employee Benefits;
- Materials, Licenses, Permit & Fees; and
- Other.

Q. Do all the projects included in the test year have project plans and schedules?

A. All projects included in the test year will have project plans and target dates at levels commensurate with their current phase. Some projects are continuing from an earlier period into the test year and have more definitive project plans for delivery. When the budget is released to a project to begin the official Plan phase, the product team will develop a more specific project plan that includes progressively more detail as the project moves through its different phases. In the case of projects executed using Agile methods, a high-level plan will be developed at the start of the project that includes an estimated number of time-bound delivery cycles, or sprints, in which the targeted scope backlog will be delivered.

INVESTMENT PROJECTS

Q. Please provide a description of the various IT investment business categories or product lines to be highlighted in testimony.

A. Costs, descriptions, benefits, alternatives, and other relevant project information for each individual project can be found in Confidential Exhibits A-20 (SHB-5) and A-21 (SHB-6). The IT investment projects are grouped into the following areas for explanation in testimony:

- **Gas and Electric & Gas Shared** projects that enable the NGDP for Asset Management; Work Management; System Automation and Control, Security and Privacy; and Advanced Analytics that are necessary components to enable the Company to be an energy partner that customers, regulators, and the people of Michigan can count on to provide safe, affordable, reliable, and clean gas system;

- **Customer** projects that are necessary to enable the Company to comply with regulatory billing changes, improve billing functionality, implement capabilities to assist low-income customers with energy assistance, increase the Company's ability to serve customers within the channel of their choice, and engage customers to enroll in demand response and energy waste reduction programs;

- **Corporate** projects that support internal departments of the Company are crucial to running an efficient business such as Treasury; Tax; Legal; HR, also known as People and Culture; Governmental, Regulatory and Public Affairs; Supply Chain and Facilities, also known as Operations Support; Finance; and Risk & Compliance;

- **IT/Digital Foundation** projects create the technology platforms, tools, processes, and frameworks that are required to enable NGDP, and customer service outcomes. This includes ARP, application currency, upgrade and replacements, and digital and foundation capabilities projects; and

- **Security** projects are necessary to deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal effect if or when a threat occurs, comply with all governmental and industry regulations, and enable the Company and its customers outcomes

<u>IT Projects Enabling Other Areas</u>

Q. Please explain the Gas and Electric & Gas Shared projects enabling NGDP.

A. Below are the projects enabling NGDP. Investments in digital capabilities are essential to achieving the Company's NGDP business plan and Work Management improvements. A synopsis of each project with its value is included in the testimony of other Company witnesses, as indicated below.

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M	Witness
Compression Air Permit and Compliance Digitalization	$385,213	$308,170	$38,105	Timothy K. Joyce
Gas Distribution Probabilistic Risk Model	$1,271,603	$1,017,283	$11,033	Lincoln D. Warriner
Gas SCADA Software Solution	$1,339,822	$1,071,858	$171,959	Lincoln D. Warriner
Gas T&D Historian	$127,269	$101,815	$37,450	Lincoln D. Warriner
Tracking and Traceability	$6,619,263	$5,295,411	$508,607	Lincoln D. Warriner
Standard Work Plan	$48,320	$38,656	$98,400	James P. Pnacek

Additionally, the Application Currency-Gas-O&M and Capital, Application Currency-Electric & Gas Shared-O&M and Capital, Product Family Enhancements-Gas-O&M and

Capital, and Product Family Enhancements-Electric & Gas Shared-O&M and Capital will be discussed later in my testimony.

Q. Are there any Gas projects with variances from the previous Case No. U-21490 that you would like to discuss?

A. Yes. The following Gas project is addressed below.

- Gas SCADA Software Solution

Q. Please recap the Gas SCADA Software Solution project.

A. The Gas SCADA Software Solution project will replace the current Gas SCADA Software with a more standardized software package enabling the Company to more efficiently meet Federal and MPSC requirements.

- **Problem Statement:** The current Gas SCADA software solution was originally implemented in 2000 and was based on the gas system requirements at that time. While the solution has been maintained since its implementation, the Company's gas system has outgrown the current capabilities. As the solution ages, there is increased effort required to address obsolete application and database software architecture, and enhancements to the system are limited. To address the capability gaps, custom interim fixes and integrations have been developed where each requires maintenance and support. This environment adds complexity and cost to solution upgrades and troubleshooting issues. The current Gas SCADA solution will limit the ability to invest in digital solutions for increased system health monitoring and preventative maintenance capabilities due to the complexity to integrate these future capabilities with it.

- **Objectives:** The project will add value by: (1) reducing risk of non-compliance by improving the ability to document and follow State and Federal requirements, improving customer safety; (2) improving efficiency and reliability when performing routine software upgrades, because standard out-of-the-box software has less risk of breaking during upgrades, as opposed to more custom-coded software; (3) reducing maintenance costs due to fewer individual software programs and less custom code; (4) improving Gas Control management capabilities that support the Federal and MPSC requirements for gas pipeline and Gas Distribution companies; (5) improving reliability by using proven gas industry standardized software with configuration features, rather than a fully customized system that has the possibility of being impacted by the next version update; (6) purchasing standard, out-of-the-box software that meets a high percentage of requirements and avoids multiple custom applications and specially coded programs to achieve results; and (7) providing a basis for capturing data required for use in computer-based preventative maintenance programs and more predictive technologies. In addition, implementing industry-specific software helps the collective gas industry users to encourage the vendor development of future version enhancements, which adds more value to gas industry users. The comprehensive Gas SCADA system is used to monitor and control the operating conditions of the transmission and distribution gas systems. The Gas SCADA system includes remote terminal units (RTUs), field devices (i.e. valves, meters, odorizers), and computers running SCADA software. This scope covers the Gas SCADA software solution only.

- **Scope:** The project scope includes the following: (1) significant planning, including consulting assistance, to define the implementation strategy for the effort, given the magnitude of the technology effort; (2) selection and implementation of a new Gas SCADA software solution; (3) planning of a phased rollout of new hardware and software; and (4) retirement and decommissioning of the legacy gas SCADA solution and equipment once the new system is fully tested and operational.

- **Alternatives:** Alternatives considered include: (1) continue to maintain the current solution, at the risk of increasing reliability issues that result in controlling and monitoring the Company's gas system; (2) invest in enhancing the existing Gas SCADA software solution which would introduce additional custom development and more specialized functions that may not be supported in future vendor releases; and (3) replace the solution with a Gas SCADA software solution that meets requirements to support the NGDP. Alternative three has been selected to ensure sustainability for this critical solution. The current legacy system is operating at well beyond its original design specification, so the potential points of failure are not fully known or understood. If the SCADA project is not completed, the legacy system could become unstable and impact Gas Control's ability to operate and monitor real-time system conditions, maintain safe operations, and comply with regulatory requirements. It could also impact the ability to commission new facilities which require remote monitoring or control or cause the need for 24/7 manual field monitoring of certain facilities.

Q. What were the total projected capital expenditures for the Gas SCADA Software Solution project in Case No. U-21490?

A. The Case No. U-21490 projected capital expenditures by year and cost category for the Gas SCADA Software Solution project are in the table provided below.

Gas SCADA Software Solution			
Case No. U-21490			
Cost Category	Total Company	Gas Allocation	
	Capital	Capital	U-21490 Reference
2023 Projected			
Software	$400,000	$400,000	A-22 (SHB-5), line 170, column l
Material	$200,000	$200,000	A-22 (SHB-5), line 170, column m
Labor	$353,273	$353,273	A-22 (SHB-5), line 170, column n
Contractor Costs	$1,133,000	$1,133,000	A-22 (SHB-5), line 170, column o
Overhead & Other Costs	$426,345	$426,345	A-22 (SHB-5), line 170, column p
Total 2023 Projected	**$2,512,618**	**$2,512,618**	A-22 (SHB-5), line 170, column k
2024 Projected			
Software	$985,282	$985,282	A-22 (SHB-5), line 247, column l
Material	$1,147,152	$1,147,152	A-22 (SHB-5), line 247, column m
Labor	$901,900	$901,900	A-22 (SHB-5), line 247, column n
Contractor Costs	$2,144,475	$2,144,475	A-22 (SHB-5), line 247, column o
Overhead & Other Costs	$1,006,673	$1,006,673	A-22 (SHB-5), line 247, column p
Total 2024 Projected	**$6,185,482**	**$6,185,482**	A-22 (SHB-5), line 247, column k
2025 Projected			
Software	$212,500	$212,500	A-22 (SHB-5), line 317, column l
Material	$0	$0	A-22 (SHB-5), line 317, column m
Labor	$653,720	$653,720	A-22 (SHB-5), line 317, column n
Contractor Costs	$1,357,238	$1,357,238	A-22 (SHB-5), line 317, column o
Overhead & Other Costs	$569,642	$569,642	A-22 (SHB-5), line 317, column p
Total 2025 Projected	**$2,793,100**	**$2,793,100**	A-22 (SHB-5), line 317, column k

Total Projected			
Software	$1,597,782	$1,597,782	
Material	$1,347,152	$1,347,152	
Labor	$1,908,893	$1,908,893	
Contractor Costs	$4,634,713	$4,634,713	
Overhead & Other Costs	$2,002,660	$2,002,660	
Total Projected	**$11,491,200**	**$11,491,200**	

Q. What are the current projected total project costs broken down by year for the Gas SCADA Software Solution project?

A. The total project costs broken down by year for the Gas SCADA Software Solution project are in the table provided below.

Gas SCADA Software Solution			
Case No. U-21806			
Cost Category	**Total Company**	**Gas Allocation**	
	Capital	**Capital**	**U-21806 Reference**
2023 Actuals			
Software	$708,742	$708,742	A-20 (SHB-5), line 67, column m
Material	$946,533	$946,533	A-20 (SHB-5), line 67, column n
Labor	$53,782	$53,782	A-20 (SHB-5), line 67, column o
Contractor Costs	$219,054	$219,054	A-20 (SHB-5), line 67, column p
Non-Labor Overhead	$4,241	$4,241	A-20 (SHB-5), line 67, column q
Non-Labor Other	$17,212	$17,212	A-20 (SHB-5), line 67, column r
Total 2023 Actuals	**$1,949,564**	**$1,949,564**	A-20 (SHB-5), line 67, column l
2024 Projected			
Software	$555,511	$555,511	A-20 (SHB-5), line 171, column m
Material	$855,345	$855,345	A-20 (SHB-5), line 171, column n

Labor	$1,194,638	$1,194,638	A-20 (SHB-5), line 171, column o
Contractor Costs	$4,957,904	$4,957,904	A-20 (SHB-5), line 171, column p
Non-Labor Overhead	$23,030	$23,030	A-20 (SHB-5), line 171, column q
Non-Labor Other	$441,113	$441,113	A-20 (SHB-5), line 171, column r
Total 2021 Projected	**$8,027,542**	**$8,027,542**	A-20 (SHB-5), line 171, column l
2025 Projected			
Software	$2,083,987	$2,083,987	A-20 (SHB-5), line 261, column m
Material	$7,264	$7,264	A-20 (SHB-5), line 261, column n
Labor	$956,112	$956,112	A-20 (SHB-5), line 261, column o
Contractor Costs	$3,856,564	$3,856,564	A-20 (SHB-5), line 261, column p
Non-Labor Overhead	$324,519	$324,519	A-20 (SHB-5), line 261, column q
Non-Labor Other	$810,488	$810,488	A-20 (SHB-5), line 261, column r
Total 2021 Projected	**$8,038,934**	**$8,038,934**	A-20 (SHB-5), line 261, column l
Total Actuals/Projected			
Software	$3,348,240	$3,348,240	
Material	$1,809,142	$1,809,142	
Labor	$2,204,532	$2,204,532	
Contractor Costs	$9,033,522	$9,033,522	
Non-Labor Overhead	$351,790	$351,790	
Non-Labor Other	$1,268,814	$1,268,814	
Total Actuals/Projected	**$18,016,040**	**$18,016,040**	

Q. Why have the projected costs of the Gas SCADA Software Solution project changed from previous projections in Case No. U-21490?

A. The initial projections provided were refined as the project progressed through investment planning and subsequent project stages in 2022 and 2023. The primary reasons for the $6.6 million increase in the Gas SCADA Software Solution project costs from the initial projections presented in Case No. U-21490 are due to increases in contractor ($4.4 million), software ($1.75 million), and material ($0.46 million) costs of $6.6 million. The contractor costs increased because the vendor professional services were underestimated in the ROM estimate. Additionally, the Company determined that a third-party was required to support internal resources with testing, as the technology is new to the Company. The software licensing costs increased because the ROM estimate planned for a five-year period, but the project required six years of software subscriptions due to the length of the implementation. The material costs increased because the ROM estimate planned to purchase physical servers, but the Company decided to purchase virtual servers. The Company utilizes virtual servers because they provide cost efficiency, maximize the use of available resources, and offer more flexibility.

Q. Please explain the test year projects included in the Customer area.

A. Below are projects included within the Customer area. These digital investments support lower cost of customer service, increase customer engagement and enrollment in programs, and increase use of digital platforms. A synopsis of each project with its value is included in the direct testimony of Company witness Jessica R. Byrom:

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	O&M
Customer Order Service Tracker	$547,715	$438,172	$150,951
Genesys Cloud Migration	$0	$0	$5,392

Additionally, the Application Currency-Customer-O&M and Capital and Product Family Enhancements-Customer-O&M and Capital will be discussed later in my testimony.

Q. Please explain the projects included in the Corporate area.

A. Below are projects included within the Corporate area. These digital solutions can optimize and even transform these foundational services. A synopsis of each project with its value is included in the direct testimony of Company witness Matthew J. Foster:

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M
2025 Union Contract Changes	$0	$0	$105,726
Expense Reporting Improvements	$154,374	$123,499	$43,532
Talent Management Enablement	$28,868	$23,095	$5,950
Enterprise Risk Management	$0	$0	$26,423
Self Service Vendor Portal	$35,311	$28,248	$39,811

Additionally, the Application Currency-Corporate-O&M and Capital and Product Family Enhancements-Corporate-O&M and Capital will be discussed later in my testimony.

<u>**IT/Digital Foundations and Capabilities**</u>

<u>**ARP**</u>

Q. Please explain the value of projects included in ARP, and how the Company determines the hardware refresh frequency.

A. The Company's ARP projects replace technology assets in line with industry and Company life-cycle expectations for the specific assets in each type of program. Replaced assets are recycled, donated, or sold if there is residual value. The Company's research shows that industry standards on refreshing hardware are generally three to five years, although the

Company refreshes monitors every eight years based on Company data related to historical failure rates. Refreshing hardware at the recommended cycle allows the Company to: (1) reduce security risks and help ensure devices are updated and patched to avoid vulnerabilities; (2) avoid costs due to increasing hardware failures; (3) avoid frustration for its customers and lost productivity for its employees due to downtime; (4) receive continued operating system support as older versions are retired by the manufacturer; and (5) ensure employees have the required hardware to support their work.

Below is a link to information on industry standards the Company has reviewed in determining its hardware refresh time periods:

- Michigan.gov, Information Technology Equipment Life Cycle: https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_FY_2021_717757_7.pdf

Q. Please describe Exhibit A-22 (SHB-7).

A. Exhibit A-22 (SHB-7) shows the detailed projected and actual capital expenditures of each ARP. Specifically:

- Column (a) provides the unit description;
- Column (b) provides the average unit cost;
- Column (c) provides the total number of units for the specified year;
- Column (d) provides the total number of units for the specified year;
- Columns (e) through (f) provide total actual or projected capital expenditures for the specified year;
- Column (g) provides the total projected capital expenditures for the test year or the total actual gas allocation of capital expenditures for the specified year; and
- Column (h) provides gas allocation of capital expenditures for the specified year.

Q. Please explain the ARP and infrastructure projects, as reflected in Exhibit A-22 (SHB-7).

A. The following are the ARP and infrastructure projects:

- The **ARP-Collaboration** project requires $521,622 in capital and $82,999 in O&M in the test year.
    - **Description:** This project will replace the Company's obsolete or out-of-date audio, visual, telephony, and other communication collaborative tools and equipment.
    - **Problem Statement:** When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.
    - **Objectives:** This project creates value by: (1) ensuring that the Company's audio, visual, telephony, and other communications systems are stable and reliable; and (2) migrate to new collaboration assets.
    - **Scope:** The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for evolving business requirements.
    - **Alternatives:** The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only. These alternatives were not chosen due to the risk inherent with a partial replacement of assets, which includes: (1) a reduced supply of equivalent replacement Avaya parts that are no longer being produced; and (2) an erosion of the knowledge technicians possess on discontinued systems.
- The **ARP-Core Network** project requires $141,383 in capital and $10,542 in O&M in the test year.
    - **Description:** This project will refresh the Data Center network equipment.
    - **Problem Statement:** When network assets that are used to support customer interactions and ensure the stability of mission critical business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

- **Objectives:** This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; and (4) standardizing network infrastructure across Data Centers.

- **Scope:** The project scope includes the replacement of all core network devices with next generation devices.

- **Alternatives:** The alternative considered was to continue running in the current state or delay the replacement of network devices and accept the risk of further business and customer impact when more equipment failures occur.

- The **ARP-Cyber Security** project requires $218,482 in capital and $9,302 in O&M in the test year.

  - **Description:** This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions.

  - **Problem Statement:** When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.

  - **Objectives:** This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.

  - **Scope:** The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three- to five-year hardware lifecycle; and (2) performing application upgrades.

  - **Alternatives:** As part of the review process, the alternatives considered were to: (1) upgrade or replace only those assets identified in the plan; (2) upgrade or replace a portion of the assets identified in the plan. Option 1 was not chosen based on continued refresh cycle for cyber security assets to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. Option 2 was not chosen due to the security risk inherent with not replacing assets as per standard refresh cycles increased system vulnerabilities, and out-of-warranty repair costs.

- The **ARP-Infoblox Refresh** project requires $157,986 in capital and $13,270 in O&M in the test year.

  - **Description:** This project will replace the three legacy core components, Domain Name System ("DNS"), Dynamic Host Configuration Protocol

("DHCP"), and Internet Protocol Address Management ("IPAM") (collectively, "DDI") environment with a modern, vendor supported system. Infoblox is the DDI solution that the Company uses to enable seamless network communications across critical systems.

- **Problem Statement:** When Infoblox assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

- **Objectives:** The value of this program includes: (1) enabling the Company to efficiently manage and control their networks; and (2) providing DNS, DHCP, and IPAM.

- **Scope:** The scope of this project includes the replacement of DNS, DHCP and IPAM assets on a five- to seven-year refresh cycle.

- **Alternatives:** The alternative considered was to continue operating on existing Infoblox equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes. The alternative to replace the existing Infoblox equipment with the latest hardware and software provided by the vendor was selected to avoid these risks and continue a regular refresh cycle.

* The **ARP-Local Area Network ("LAN")** project requires $231,181 in capital and $18,280 in O&M in the test year.

    - **Description:** This project will upgrade the Company's entire LAN and a significant portion of the Wireless Local Area Network ("WLAN").

    - **Problem Statement:** At some Company locations, LAN equipment has been in service since 2011. If the LAN/WLAN hardware and software is not routinely refreshed, the Company will lose the manufacturer support needed for equipment bug fixes, security vulnerability patches, and enhancements. In addition, aging equipment cannot accommodate the increasing demand for wireless devices necessary to perform day-to-day operations that rely on wireless-enabled devices, such as rugged field devices, cell phones, barcode scanners, tablets, and other mobile devices. As equipment ages, it is at risk of higher failure rates, which increases the risk of unplanned outages. In the event of unplanned outages, business areas would not be able to access services on the corporate network including email, SAP, internet, and phones.

- **Objectives:** The project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor supported, thereby ensuring support for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; (6) increasing user productivity through a higher performing wireless network, which increases the productivity and efficiency of office and field employees serving customers; and (7) improving support for wireless Internet Protocol ("IP") phones, Internet of Things ("IoT") and field devices.

- **Scope:** The project scope includes: (1) refreshing the LAN equipment and software across all Company sites; (2) identifying the required features for the new equipment; (3) implementing the new equipment according to industry best practices; (4) replacing wireless network with upgraded infrastructure and verifying wireless coverage is as expected; and (5) collecting wireless survey data for all Company locations in order to design improved wireless network coverage.

- **Alternatives:** The alternative considered was to continue operating on the existing platform past the vendors end-of-support date. The vendor support period ended in May 2021, and paying for extended support is not an option offered by the vendor. The risk inherent in not refreshing the platform is a lack of vendor support resulting in an absence of software bug fixes, security updates, and break fixes. The Company chose to replace the existing equipment with the latest hardware and software available, following a five year refresh cycle.

- The **ARP-OT Support Gas** project requires $2,468,066 in capital and $398,568 in O&M in the test year.

  - **Description:** This project will replace dated and obsolete servers on a rotating five-year refresh schedule.

  - **Problem Statement:** When OT Assets that are used to ensure the safety and reliability of technology that supports critical gas operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle.

  - **Objectives:** This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical gas infrastructure.

- **Scope:** The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new computer capacity to account for expanding business requirements.

- **Alternatives:** The alternatives considered include: (1) continue to operate hardware beyond a five- to seven-year refresh cycle or (2) refresh hardware based on a five- to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five- to seven-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety for customers, as vendors do not provide extended support after seven years. The Company chose the alternative to refresh this hardware based on a five- to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Gas SCADA.

- The **ARP-Physical Security** project requires $747,487 in capital and $4,698 in O&M in the test year.

  - **Description:** The ARP-Physical Security, formerly known as Physical Security Asset Refresh, will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns.

  - **Problem Statement:** The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster responses to emergencies and incidents. This could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage.

  - **Objectives:** The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reducing gaps in functionality; and (3) optimize overall system performance.

  - **Scope:** Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems.

  - **Alternatives:** Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security assets per an asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security concerns, incident resolution, and the inability to meet FERC requirements. The alternative selected maintains compliance, reduces redundancies and gaps in functionality, and optimizes overall performance of physical security systems.

- The **ARP-Printer Asset Management ("PAM")** project requires $118,704 in capital and $1,860 in O&M in the test year.

  - **Description:** This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one.

  - **Problem Statement:** When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

  - **Objectives:** This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications.

  - **Scope:** The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle.

  - **Alternatives:** The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years is assessed monthly to ensure it is not run-to-failure, including running the asset to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.

Q. Please explain the ARP-FDAM project.

A. The ARP-FDAM project has the following synopsis:

- The **ARP-FDAM** project requires $2,192,211 in capital and $1,860 in O&M in the test year.
  - **Description:** This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility.
  - **Problem Statement:** When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle.
  - **Objectives:** This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices prior to increasing hardware failures; and (2) allowing field workers to complete their job tasks.
  - **Scope:** The project scope consists of replacing field device assets according to the four-year refresh cycle.
  - **Alternatives:** The alternatives considered were to: (1) extend the replacement cycle from four years to five years for field devices; and (2) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the assets that need refreshing in future years based on the number of devices that were not replaced during the four year refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle to alleviate these concerns.

Q. How are the annual projected costs created for the ARP-FDAM project?

A. The ARP-FDAM project has two categories, which are replacements and new purchases. Each of these categories include field devices. A further description of replacements and new purchases is as follows:

- **Replacements:**
  - Are determined by pulling the quantity of device types with a scheduled retirement year:
    - Field devices scheduled retirement year is four years from purchase;
  - The model of device determines the unit cost. The total of these devices with their current unit cost is established for a particular year's budget;
  - Accessories for field devices are projected based on the number of planned replacements and include desk docks, vehicle docks, and ac adapters; and
  - Carryover devices are added from the previous year to address aging devices first.
- **New Purchases:**
  - Are determined based on People and Culture hiring estimations and any known field device needs of a particular work group (e.g. some field groups require large screen sizes);
  - The model of device and monitor determines the unit cost; and
  - Accessories for field devices are projected based on the number of planned new purchases.

The four-year cycle for field devices, along with the projected new purchases, are listed in the associated Exhibit A-22 (SHB-7).

Q. Please describe variances from year to year for the ARP-FDAM project.

A. Variances for the ARP-FDAM project are a result of changes to scheduled replacements per four-year field device and incremental unit cost increases. Starting in 2024, there has been a one-time change for new field device purchases. These devices are now a part of the ARP-FDAM project, rather than the ARP-WAM project. Moreover, there is a change in the replacement of some field devices, which were initially planned under the ARP-WAM project. These devices were included in ARP-FDAM starting in the year 2024. Exhibit A-22 (SHB-7), page 4, details the devices, number of units, and unit costs for each type of device. Below are summary charts with the variance reasons for each year separated between replacement and new purchase categories.

Replacements

Year	Field Device	Reason for variance
2023 Actual	715	Field device replacements based on refresh schedule.
2024 Plan	678	• Field device replacements based on refresh schedules. • 84 field device replacements moved from ARP-WAM to ARP-FDAM.
2025 Plan	538	Field device replacements based on refresh schedule.
2026 Plan	1,325	Field device replacements based on refresh schedule.

New Purchases

Year	Field Device	Reason for variance
2023 Actual	0	140 field devices new purchases based on actual new employee/contractor volume and were accounted for as part of ARP-WAM, not ARP-FDAM.
2024 Plan	107	Projection for 2024 based on People and Culture estimated hiring, which were previously projected as a part of ARP-WAM.
2025 Plan	200	Projection for 2025 based on People and Culture estimated hiring.
2026 Plan	200	Projection for 2026 based on People and Culture estimated hiring.

Q. Do the Company's 2025 projected gas allocation capital expenditures for material costs for the ARP-FDAM project differ from the $1,476,310 projected in Case No. U-21490?

A. Yes. The 2025 projected gas allocation capital expenditures for material costs for the ARP-FDAM project of $1,061,230 (Confidential Exhibit A-20 (SHB-5), line 273, column (n)) is $415,080 less than the $1,476,310 projected in Case No. U-21490 (Exhibit A-20 (SHB-5), column (m), line 329.

The following describes the reason for the difference:

1. Field device replacements decrease of $0.4 million that were initially projected as a part of ARP-WAM in Case No. U-21490; and

2. Accessories increased by $0.01 million associated with projected new purchases of field devices.

Q. Please explain the ARP-Radio project.

A. The ARP-Radio project has the following synopsis:

- The **ARP-Radio** project requires $1,200,164 in capital and $75,865 in O&M in the test year.

  - **Description:** This project will refresh hardware to include 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices and vehicle consoles in service trucks. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled seven-year lifecycle basis. Cellular modems are refreshed on a five-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle.

  - **Problem Statement:** Vehicle consoles are typically retired with the vehicle but are salvaged for reuse in new vehicles when possible. 800MHz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customer service and critical infrastructure. Company radio systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing. The refresh of these subscriber units in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety.

  - **Objectives:** This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure.

- **Scope:** The project scope consists of: (1) scheduled replacement of radios, modems, and consoles; (2) installing additional radios modems and console assets to satisfy growth requirements; and (3) scheduled replacement of out-of-date cellular and radio boosters.

- **Alternatives:** The alternatives considered included: (1) Replace the existing units with new units from other radio and modem manufacturers; and (2) purchase new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.

Q. Do the Company's 2023 actual gas allocation capital expenditures for material costs for the ARP-Radio project differ from the $459,501 projected in Case No. U-21490?

A. Yes. The 2023 actual gas allocation capital expenditures for material costs for the ARP-Radio project of $304,384 (Confidential Exhibit A-20 (SHB-5), column (n), line 75) are $155,117 less than the $459,501 projected in Case No. U-21490 (Exhibit A-20 (SHB-5), column (m), line 178.

The difference is explained by the Company being able to avoid purchasing 100 Havis boxes due to its decision to reduce the number of Company vehicles. The Havis boxes from the vehicles that were sold have been repurposed. Additionally, the Company conducted a request for proposal for the radios planned for 2024, which has resulted in a lower radio unit cost. However, the purchase of bi-directional amplifiers deferred from 2022 that are end of life and require refresh to support newer cellular technologies (such as 5G) offset some of these savings.

Q. Please explain the ARP-Server and Storage project.

A. The ARP-Server and Storage project has the following synopsis:

- The **ARP-Server and Storage** project requires $694,196 in capital and $158,399 in O&M in the test year.
    - **Description:** This project will replace or augment server and storage infrastructure for the Company.
    - **Problem Statement:** When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be more challenging to keep current with Security updates. The Company also runs the risk of failure of these assets impacting customer interactions and business operations if it does not adhere to a regular five- to seven-year refresh cycle.
    - **Objectives:** This project creates value for the Company through: (1) improved stability and availability of business-critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use.
    - **Scope:** The scope of this program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements.
    - **Alternatives:** The alternatives considered were to purchase extended maintenance, move some of these assets to the cloud with the Digital-Hybrid Cloud and Data Center Migration project, or to replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital-Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option. If the Digital-Hybrid Cloud and Data Center Migration project is not approved as part of this rate case, the Company plans to continue to refresh these critical technologies at the current level based on a five- to seven-year refresh cycle to mitigate the risk of failure.

Q. Do the Company's 2024 projected gas allocation capital expenditures for material costs for the ARP-Server and Storage project differ from the $579,318 projected in Case No. U-21490?

A. Yes. The 2024 projected gas allocation capital expenditures for material costs for the ARP-Server and Storage project of $200,604 (Confidential Exhibit A-20 (SHB-5), column (n), line 185) are $378,714 less than the $579,318 projected in Case No. U-21490 (Exhibit A-20 (SHB-5), column (m), line 260.

The difference is explained by the Company's decision to migrate to SAP HANA database in 2023, which is discussed later in my testimony. As a result, the Company did not proceed with refreshing the SAP infrastructure.

Q. Please explain the ARP-WAM project.

A. The ARP-WAM project has the following synopsis:

- The **ARP- WAM** project requires $2,060,439 in capital and $24,426 in O&M in the test year.
    - **Description:** This project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates.
    - **Problem Statement:** When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.
    - **Objectives:** This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks.
    - **Scope:** The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources.

- **Alternatives:** The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP in future years based on the number of devices that were not replaced during the four year refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets; and an eight-year cycle for monitors to alleviate these concerns.

Q. Would increasing the replacement cycle for the ARP-WAM refresh cycle from four years to five to seven years have a negative impact on the Company and its customers?

A. Yes. Increasing the replacement cycle for Personal Computer ("PC") Devices from four years to five to seven years would have a negative impact on the Company and its customers. This is demonstrated through industry data, internal incident data, PC warranty duration, and lost productivity.

- These references reinforce replacing PCs at four years or less:
  - Michigan.gov, Information Technology Equipment Life Cycle. https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_FY_2021_717757_7.pdf
  - https://i.crn.com/sites/default/files/ckfinderimages/userfiles/images/crn/custom/INTELBCCSITENEW/WhitePaper_EnterpriseRefresh.pdf
- The vendor's three-year warranty duration for Company PCs combined with the incident history reinforce four years is the optimum time for replacement.

The labor cost of addressing incidents and lost productivity, the warranty period, and external references confirm PC and field device replacement on a four-year cycle.

Similarly, Company historical failure rates for monitors indicate an eight-year cycle as ideal, which is what the Company employs for monitors.

Q. How are the annual projected costs created for the ARP-WAM project?

A. The ARP-WAM project has two categories, which are replacements and new purchases. Each of these categories include PC devices and monitors. A further description of replacements and new purchases is as follows:

- **Replacements:**
  - Are determined by pulling the quantity of device types with a scheduled retirement year:
    - PC devices scheduled retirement year is four years from purchase, and
    - Monitors scheduled retirement year is eight years from purchase.
  - The model of device determines the unit cost. The total of these devices with their current unit cost is established for a particular year's budget;
  - Accessories for PC devices are projected based on the number of planned replacements and include keyboards, surge protectors, docks, backpacks, and cables; and
  - Carryover devices are added from the previous year to address aging devices first.
- **New Purchases:**
  - Are determined based on People and Culture hiring estimations and any known PC device needs of a particular work group (e.g. some engineering groups require high performance devices);
  - Associated new monitors to go along with the PC devices are identified;
  - The model of device and monitor determines the unit cost; and
  - Accessories for PC devices are projected based on the number of planned new purchases.

The four-year cycle for PC devices and the eight-year cycle for monitors, along with the projected new purchases, are listed in the associated Exhibit A-22 (SHB-7).

Q. Please describe variances from year to year for the ARP-WAM project.

A. Variances for the ARP-WAM project are a result of changes to scheduled replacements per four-year PC device and eight-year monitor refresh cycles, previous year deferrals for equipment replacements primarily due to disallowances, and incremental unit cost increases. Starting in 2025, there has been a one-time change for new field device purchases. These devices will now be a part of the ARP-FDAM project, rather than the ARP-WAM project. Moreover, there is a change in the replacement of some field devices, which were initially planned under the ARP-WAM project. Exhibit A-22 (SHB-7), page 12, details the devices, number of units, and unit costs for each type of device. Below are summary charts with the variance reasons for each year separated between replacement and new purchase categories.

Replacements

Year	**PC Device**	**Monitor**	**Reason for variance**
2023 Actual	2,153	0	• 296 PC devices that could not be replaced due to disallowances were deferred to 2023. • 118 PC devices that could not be replaced due to resource availability were deferred from 2023 to 2024.
2024 Plan	1,869	105	• 118 PC devices that could not be replaced due to resource availability were deferred from 2023 to 2024. • Monitor replacements associated with 118 PC devices that were deferred to 2024. • 1,015 PC devices that are not planned to be replaced due to reduction in resources.
2025 Plan	3,376	0	• No monitor replacements planned since monitors' eight-year replacement cycle was completed 2018-2021. The next monitor replacement is targeted to resume in 2027.
2026 Plan	2,215	0	• No monitor replacements planned since monitors' eight-year replacement cycle was completed 2018-2021. The next monitor replacement is targeted to resume in 2027.

New Purchases

Year	PC Device	Monitor	Reason for variance
2023 Actual	284	171	Based on actual new employee/contractor volume.
2024 Plan	197	145	• 248 fewer PC devices for 2024 based on People and Culture estimated hiring. • 220 fewer monitors for 2024 based on People and Culture estimated hiring.
2025 Plan	393	400	Projection for 2025 based on People and Culture estimated hiring.
2026 Plan	393	400	Projection for 2026 based on People and Culture estimated hiring.

Q. Do the Company's 2023 actual gas allocation capital expenditures for material costs for the ARP-WAM project differ from the $2,268,452 projected in Case No. U-21490?

A. Yes. The 2023 actual gas allocation capital expenditures for material costs for the ARP-WAM project of $1,873,353 (Confidential Exhibit A-20 (SHB-5), column (m), line 83) are $395,099 less than the $2,268,452 projected in Case No. U-21490 (Exhibit A-20 (SHB-5), column (m), line 186).

The following describes the difference:

1. Desktop replacements decreased by $0.03 million due to 118 replacements being deferred to 2024 due to time needed to analyze whether the devices should be replaced or collected based on usage and offset by reduction in resources;
2. Laptop and rugged device replacements decreased by $0.41 million due to reduction in resources;
3. Accessories decreased by $0.09 million; and
4. New PC purchases increased by $0.21 million based on actual hiring.

Q. Do the Company's 2024 projected gas allocation capital expenditures for material costs for the ARP-WAM project differ from the $2,071,350 projected in Case No. U-21490?

A. Yes. The 2024 projected gas allocation capital expenditures for material costs for the ARP-WAM project of $1,712,808 (Confidential Exhibit A-20 (SHB-5), column (n), line 186) are $358,542 less than the $2,071,350 projected in Case No. U-21490 (Exhibit A-20 (SHB-5), column (m), line 261).

The following describes the difference:

1. Desktops and monitor replacements were net neutral due to 118 replacements being deferred, as discussed above, then offset by replacements not needed due to reduction in resources;
2. Laptop and tablets replacements decreased by $0.25 million based on reductions in resources;
3. RT Mount device increased by $.13 million;
4. Accessories decreased by $0.1 million; and
5. New PC and monitor purchases decreased by $0.14 million based on projected hiring.

Upgrades, Replacements, and Application Currency Projects

Q. What are Upgrades, Replacements, and Application Currency projects?

A. Upgrades, Replacements, and Application Currency projects are projects that address the need to upgrade or replace software applications and underlying platforms to a more current version to maintain prudent levels of security, reliability, and interoperability with associated systems. The Company performs security risk and various types of technical analysis to determine which applications need upgrading or replacing and when. Upgrade and replacement projects are created for larger and more complex application and platform upgrades or replacements that require increased oversight and project management.

Smaller upgrades are aggregated by IT product line and spend type in the Application Currency projects.

Q. Please explain the Upgrades and Replacements projects.

A. The following is an explanation of the Upgrades and Replacements projects:

- The **Asset Accounting Tax Upgrade** project requires $126,165 in O&M in the test year.
    - **Description:** The project will upgrade the Company's current accounting asset management tax software to the SaaS version as required by the vendor or a replacement solution and implement additional new features, ensuring continued support of a critical financial application, and providing new functionality.
    - **Problem Statement:** In 2025, standard vendor support ends for the current on-premise PowerTax software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility.
    - **Objectives:** This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) moving to a SaaS solution in order to stay supported; and (2) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.
    - **Scope:** The project scope includes: (1) evaluating current vendor/product solution with market leaders; and (2) upgrading the vendor software from the current version to the newer SaaS version or replacing it.
    - **Alternatives:** Alternatives considered include: (1) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (2) Do nothing and remain on unsupported, on-prem tax solution. This option introduces technical and financial risk which would be costly. (3) Upgrade to the newest SaaS version of current on-prem solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and

server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **Asset Accounting Upgrade 2025-2026** project requires $58,931 in O&M in the test year.

    - **Description:** The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application.

    - **Problem Statement:** In 2027, standard vendor support ends for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility.

    - **Objectives:** This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; and (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.

    - **Scope:** The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor software from the current version to the newer version.

    - **Alternatives:** Alternatives considered include: (1) Evaluate SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) Upgrade to the newest version of current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **Energy Assistance Enhancements and Maintenance Annual Updates** project requires $123,769 in O&M in the test year.

  - **Description:** The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy ("CARE") project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interfaces and updates to SAP to process various requests. Upcoming modifications will be identified following an ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services ("DHHS") and the MPSC to prioritize the list of changes.

  - **Problem Statement:** Each grant year, DHHS and the MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track active CARE customers, and how they will administer the Michigan Energy Assistance Program ("MEAP") benefits through bill credits and arrears forgiveness. The criteria changes significantly each year; therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requirements are not fulfilled, the Company is at risk of losing state Low Income Home Energy Assistance Program ("LIHEAP") funds to assist low-income customers with paying their energy bills, thereby increasing the customer risk of shutoff for non-payment. In addition, the Company's energy assistance programs function within all software platforms in the Company which consistently need enhancements and updates.

  - **Objectives:** The project will provide the following value: (1) complete modifications to internal SAP application and Agency Portal to receive LIHEAP funding, which can be used to provide customers bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LIHEAP funding; and (3) complete modifications to customer facing platforms.

  - **Scope:** The project scope includes: (1) updating the enrollment and status process; (2) allowing for flat monthly bills; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by DHHS and the MPSC; (6) updating CARE dunning process; and (7) updating CE PASS functionality to enhance Agency Self-Service.

- **Alternatives:** Alternatives considered included: (1) continue with current process, which would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization, which would remove ownership and visibility into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. Option 3 was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems (SAP, Agency Portal, etc.), therefore a cloud or third-party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.

- The **Enterprise Service Bus Application 2024-2025 Upgrade** project requires $48,200 in O&M in the test year.
  - **Description:** This project will upgrade and migrate the Business Works developer application to the next version.
  - **Problem Statement:** Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway be more scalable, secure, and capable of integrating to a service-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of approximately $80,000 annually, this is just temporary coverage and serves only to delay the need for an upgrade.
  - **Objectives:** The value this project provides the Company includes: (1) cost avoidance to avoid extensive payments for extend support purposes; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies.
  - **Scope:** The project scope includes implementing current version of all applications that are part of the ESB application, database version, and required database drivers.
  - **Alternatives:** Alternatives considered included: (1) Accept the annual $80,000 extended maintenance cost. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meter management. The current implementation of the ESB platform was built with five years of growth in mind. This alternative was not chosen due to risk to Company operations, and the additional expense. (2) Replace the on-premise upgrade plan to implement a cloud-based solution. A cloud migration would also take longer to complete, which would put the Company at risk of falling outside of the current vendor support window for the product’s current version. (3) Upgrade the existing

application. This option was selected because it best meets the Company needs for the near future by restoring vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.

- The **HR Support Pack and Business Software Inc ("BSI") Upgrade 2025 and 2026** projects require the following O&M in the test year.

Project Year	Test Year O&M
2025	$59,576
2026	$237,741

  - **Description:** The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.
  - **Problem Statement:** SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.
  - **Objectives:** This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.
  - **Scope:** The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.
  - **Alternatives:** As this is an upgrade of an existing system, the alternative considered was to delay the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.

- The **ISIS Papyrus 2026 Upgrade** project requires $188,501 in capital ($150,801 ROM Adjusted Capital) and $85,576 in O&M in the test year.
  - **Description:** This project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The ISIS Papyrus application is critical to creating electronic and paper correspondence for customers, including bills and dunnings.
  - **Problem Statement:** The application will be at least 1 major upgrade revision behind by 2026. In addition, the infrastructure will need replacement in 2026 (both hardware and OS). It is imperative that customers retain unfettered access to their paper bills, dunning notices and other communications produced by ISIS. ISIS also makes customer bills available for online viewing through the website and mobile apps. Without

the upgrade, our vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity, and security will be forthcoming. The upgrade will address these problems and challenges, as well as ensure all other platform components comply with our company operational and security standards.

- **Objectives:** The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors.

- **Scope:** The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications.

- **Alternatives:** As this is an upgrade of an existing system, the alternative considered was to delay the upgrade and continue operating with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching.

- The **Itron Enterprise Edition ("IEE") 2025 Upgrade** project requires $48,856 in O&M in the test year.

  - **Description:** This project will upgrade IEE, which collects the reads from meters to ensure non-estimated bill accuracy.

  - **Problem Statement:** IEE is the Company's keystone application of the Advanced Metering Infrastructure, that provides billing data that includes time of use data. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. IEE is a key component in keeping the Company current, with billing capacity, stability, and accuracy obligations.

  - **Objectives:** This project creates value for the Company by: (1) ensuring the features and functionality needed to meet and exceed customer satisfaction and billing accuracy are available to business partners and IT; and (2) meeting Information Security's requirement to keep applications patched and protected from cyber attack.

  - **Scope:** The scope of this project includes: (1) upgrading the IEE applications to the next appropriate versions; (2) migrating the database to the next version required by the application; and (3) replacing hardware required by the next version to maintain operating system currency.

  - **Alternatives:** Alternatives considered included: (1) Defer the upgrade. This alternative was not selected because it would decouple IEE (the Company's Meter Data Management) from the Itron security infrastructure introducing application stability, security, and dependency risks to the utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Itron applications use, creating more expense support and no ability to leverage updated tool capability. (2) Replace the platform. Replacing IEE/MDM would require the application business owners to undertake a new initiative mirroring the expense and effort that went into the multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform the upgrade. This option is superior because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.

- The **Next Generation electronic Shift Operations Management System ("eSOMS") Replacement** project requires $157,182 in capital ($125,746 ROM Adjusted Capital) and $8,243 in O&M in the test year.

    - **Description:** The project replaces the eSOMS with updated clearance lock out tag out ("LOTO") management software for Electric Generation facilities, and narrative logs and mobile rounds functionality for Electric Generation and Gas Compression facilities.

    - **Problem Statement:** The vendor is replacing the current system used at the Company and other utilities with a new software package called Lumada. The software migration is necessary for the Company to retain vendor support, so that the databases continue to receive security patches, bug fixes, and functionality support from the vendor, and avoid security, stability, and reliability risk.

    - **Objectives:** The project will add value by: (1) maintaining functionality of a critical life safety application; (2) reducing the human struggle that comes from manual workarounds and an older application; (3) empowering employees with proper electronic tools to meet customer expectations; (4) enabling process improvements to deliver outages more effectively; (5) reducing plant downtime; (6) increasing reliability; and (7) increasing standardization across the Company.

    - **Scope:** The scope of this project includes: (1) configuring software for clearance management, logbook, rounds, automated emails, and reporting; (2) migrating and archiving data; (3) enabling additional offline capabilities, (4) integrating with SAP for equipment and current status of work orders; (5) adding new integration to SAP for notifications from rounds and clearance functions; (6) testing the software, data migrations and integrations; and (7) updating configuration management database, runbook, system recovery plan, LOTO work procedure, qualification training and other standard documentation.

- **Alternatives:** Alternatives considered include: (1) continuing to use the eSOMS application, though without vendor support. This alternative was not selected because losing vendor support for this critical application increases risks for application security, reliability, and supportability that can result in an employee safety incident in the complex tagging process, an extended plant production outage, a prolonged plant reliability issue, or regulatory or compliance violations. (2) Instituting the manual business continuity process until the application replacement is possible. This alternative was not selected because it would also increase the previously mentioned operational risks. (3) Replacing the eSOMS application by customizing SAP. This alternative was not selected as it would be more expensive and introduce additional risk to employees due to poor application fit. (4) Migrating the existing eSOMS data to an out of the box application such as the Lumada application. The option to migrate the existing eSOMS application to an out of the box solution was chosen to minimize cost and risk to the Company and its employees. Cloud hosting of the application infrastructure at the vendor's location was also evaluated, though due to the greater cost of this vendor hosting, the application infrastructure will be hosted on premise at the Company.

- The **Rate Change Maintenance** project requires $118,372 in O&M in the test year.
  - **Description:** The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements.
  - **Problem Statement:** For the Company to continue to meet and comply with the MPSC rate change requirements, there is a need to make periodic updates/modifications to the existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers.
  - **Objectives:** The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that includes new surcharges, price changes, and energy efficiency programs.
  - **Scope:** The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Company's back-end system for more efficient rate changes.
  - **Alternatives:** An alternative considered for this effort was a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and the timing it would take for testing of this

model. Cloud is not an applicable option in this case as we are not replacing any software. The option to use onshore resources to plan, coordinate, and execute the rate changes was selected as it supports the Company's operation model for rate changes.

- The **Replacement for Gas Automated Meter Reading ("AMR") Technology** project requires $856,334 in capital ($685,067 ROM Adjusted Capital) and $93,405 in O&M in the test year.

  - **Description:** This project will replace Itron Field Collection Systems ("FCS") and Itron Mobile with the newest Itron SaaS Temetra along with replacing Itron Mobile with Temetra Mobile for Gas AMR meters. This will allow the Company to leverage new cloud capabilities and align with the Company's Cloud strategy.

  - **Problem Statement:** The Company is using FCS and FCS mobile to gather gas meter reads. The vendor is replacing these systems with new Cloud software called Temetra and Temetra Mobile due to FCS and Itron Mobile being end of life December 2026. The software migration is necessary to maintain vendor support (latest security patches, bug fixes, latest functionality) while avoiding security, stability, and reliability risks for the Company. Moving to Itron Temetra will ensure no gas meter reading disruption and continued integration with existing gas communication modules and Itron Security Manager.

  - **Objectives:** The project adds value by: (1) continuing to collect accurate and timely gas meter reads; (2) removing the risk of being on unsupported versions; (3) utilizing the latest functionality such as retrieving historic read data, photos, and reports directly from Temetra; (4) seamlessly getting up to date security patches; (5) and reducing ongoing networking equipment replacement and upgrade costs.

  - **Scope:** Included in the implementation is: (1) configuring and deploying Temetra and Temetra Mobile; (2) migrating data; (3) integrating to IEE, Itron Security Manager ("ISM"), gas AMR PI Historian and Data Lake; (4) integrating to Mobile Collectors ("MC3s"); (5) testing the software, data migrations, and integrations; (6) educating and increasing the skills of the employees to leverage the new cloud services; and (7) decommissioning FCS and Itron Mobile and the on-premise databases and servers.

  - **Alternatives:** Alternatives considered included: (1) continuing to use the FCS application and Itron Mobile without vendor support. This alternative was not selected because it would add application stability, security, and dependency risks to gas meter reading data collection which would negatively impact critical customer billing operations. It would also de-couple from the Itron security infrastructure that the other business critical Itron applications use, creating more expense and complexity in the technology environment. (2) Replace the platform with a different mobile gas reading application, which would also require the Company to replace the 1.2 million gas communication modules on the meters. Replacing FCS would require the application business owners to undertake a large initiative requiring multiple years to implement and a multi-team effort from start to finish. It would also increase the amount of technology needed to be supported and add cost to support as it would be a standalone product. (3) Move to Itron's Cloud technology (Temetra and Temetra Mobile). This option best suits customers and the Company's needs for the future as it offers new functionality while maintaining the system integrated into the Itron Security infrastructure and with the other Itron software products in use at the Company.

- The **SAP Support Pack Upgrade 2026** project requires $329,041 in O&M in the test year.

  - **Description:** The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for the Company's business partners.

  - **Problem Statement:** To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability.

  - **Objectives:** The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility.

  - **Scope:** The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component ("ECC"), Customer Relationship Manager ("CRM"), Enterprise Portal, Process Orchestration ("PO"), Business Warehouse ("BW"), Business Objects ("BOBJ"), Data Services ("DS"), Solution Manager, Data Quality Manager ("DQM"), Graphical User Interface ("GUI"), Single Sign On ("SSO"), System Landscape Directory ("SLD"), and other related SAP applications.

  - **Alternatives:** Alternatives considered include: (1) Divide the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) Migrate to SAP S/4HANA. This option was not selected, because SAP S/4HANA is a multi-year project that is not expected to be completed by year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3) Balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.

- The **SiteCore Primary Upgrade 2025** project requires $6,099 in capital ($4,879 ROM Adjusted Capital) and $15,195 in O&M in the test year.
  - **Description:** The project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for the consumersenergy.com website.
  - **Problem Statement:** Sitecore is currently operating on version 10.3, which is due to end mainstream support at the end of 2025. If this occurs, there will be an increase in support and maintenance fees of 10% above the annual subscription spend.
  - **Objectives:** The project will add value for the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to-date security posture; and (3) supporting the Company's goals by improving reliability and performance.
  - **Scope:** The project scope includes: (1) upgrading the Sitecore content management software to include content hosting and delivery allowing the use of new features and functionality; and (2) migrating the Sitecore platform to the most up-to-date hardware and software by refreshing the application and database servers to a newer version of Windows Server and SQL Server.
  - **Alternatives:** Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the current version falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Undergo a full website redesign. This solution was not chosen as a similar effort is already slated to begin in 2024; and (3) Upgrade Sitecore on a two-year cycle. This alternative was chosen as it provides up-to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.

- The **Software Platform Refresh** project requires $42,219 in O&M in the test year.
  - **Description:** The Software Platform Refresh project will upgrade server operating systems, hypervisors, databases, and infrastructure platforms to retain low-cost vendor support.
  - **Problem Statement:** For systems that go beyond their normal manufacturer support ending, there will be increased support and maintenance fees of 20% to 100% above current support and maintenance depending on vendor. Completing this project allows the organization to (1) avoid high support costs; (2) provide for system security; and (3) stay current to promote seamless interoperability among servers, applications, and databases. Aging servers are more susceptible to security vulnerabilities and performance issues that ultimately could affect the business and customers.
  - **Objectives:** The project will add value for the Company by: (1) avoiding costs for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring reliability and compliance with Information Security requirements; (3) improving data center environment stability; and (4) avoiding the need for high risk upgrades that cross multiple versions.
  - **Scope:** The project scope includes: (1) upgrading operating systems and databases on servers that are near end of support with a given vendor; and (2) maintaining hypervisors at the current version for stability and performance.
  - **Alternatives:** A funding options matrix was completed to review the potential alternatives. The alternatives identified were: (1) Complete the full scope of the solution for $1 million in order to eliminate the need for ongoing extended support; (2) Reduce the scale of the solution, which requires $1.6 million in ongoing extended support; (3) Reduce the scale of the solution even further, which requires $2.4 million in ongoing extended support; (4) Do not complete a software platform refresh, which requires $3.3 million in ongoing extended support. Alternative 1 was selected as the most cost effective solution to ensure ongoing system stability; seamless integration; and mitigation of cyber-security risks without the significant cost of extended support necessary for End of Life software systems.

Q. Please describe Confidential Exhibit A-23 (SHB-8).

A. Confidential Exhibit A-23 (SHB-8) is a confidential exhibit that provides Application Currency Program projected capital and O&M spend and scope for each of the Application Currency projects. Specifically:

- Column (a) provides the application name;
- Column (b) provides a disaster recovery Tier, where applicable;
- Column (c) provides total projected 2025 capital expenditures;
- Column (d) provides total projected 2025 O&M expense;
- Column (e) provides total projected 2026 capital expenditures;
- Column (f) provides total projected 2026 O&M expense;
- Column (g) provides total test year capital expenditures;
- Column (h) provides total test year O&M expense;
- Column (i) provides the gas allocation for test year capital expenditures; and
- Column (j) provides the gas allocation for test year O&M expense.

Application Currency information can be used to exploit known security vulnerabilities; therefore, the exhibit is confidential.

Q. How does the Company decide which applications to include in the Application Currency Program for the test year?

A. The Application Currency Program focuses on upgrades that maintain security and reliability of the application and underlying platforms, as well as maintaining vendor supported software versions. Not every application requires an upgrade each year, so the application data provided in Confidential Exhibit A-23 (SHB-8) is not inclusive of all applications that are in upgrade cycles beyond the test year. The Company considers the following when determining the next upgrade version:

- Compatibility with the current environment and underlying platforms;
- Compatibility with associated or integrated applications;
- Future planned changes that could sub-optimize the application;
- Cyber security drivers and requirements;
- Additional functionality offered with the new version; and
- Availability of the appropriate version.

The applications meeting the criteria for upgrade are then added to the application currency list, cross-checked against other current or future projects that may impact the upgrade, and then scheduled.

Q. Please explain the Application Currency projects.

A. The following describes the Application Currency projects:

The **Application Currency - Capital** and **Application Currency - O&M:**

- **Description:** These initiatives will utilize capital and O&M funding to keep applications current for security and reliability. O&M is included with capital projects to complete expense activities associated with capital upgrades.
- **Problem Statement:** The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.
- **Objectives:** Maintaining the appropriate versions of applications through application currency upgrades adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software;

and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.

- **Scope:** The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes.

- **Alternatives:** Applications are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

Specific spend requirements for each Application Currency project are indicated in the table below and supported with additional detail in Confidential Exhibit A-23 (SHB-8).

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Projected Test Year O&M
Application Currency-Corporate-Capital	$54,038	$43,230	$5,972
Application Currency-Corporate-O&M	$0	$0	$123,245
Application Currency-Customer-O&M	$0	$0	$55,307
Application Currency-Electric & Gas Shared-Capital	$109,408	$87,527	$18,064
Application Currency-Electric & Gas Shared-O&M	$0	$0	$227,608

Application Currency-Gas-Capital	$30,458	$24,367	$0
Application Currency-Gas-O&M	$0	$0	$231,653
Application Currency-IT/Digital Foundation-Application Platforms-Capital	$51,388	$41,110	$66,220
Application Currency-IT/Digital Foundation-Application Platforms-O&M	$0	$0	$95,756
Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	$0	$0	$13,128
Application Currency-Operational Technology-Capital	$46,318	$37,055	$17,199
Application Currency-Operational Technology-O&M	$0	$0	$107,459
Application Currency-Security-Capital	$45,951	$36,761	$3,604
Application Currency-Security-O&M	$0	$0	$121,386

<u>Enhancement Projects</u>

Q. Please describe Exhibit A-24 (SHB-9).

A. Exhibit A-24 (SHB-9) is the Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis. Page 1 provides a summary of enhancement projected and actual spend for the years 2019 through 2026. Specifically:

- Column (a) provides the year reference;
- Column (b) identifies the gas case where the projected or actual amounts were provided;
- Column (c) identifies the exhibit number where the projected or actual amounts were provided;
- Columns (d) through (k) identify the projected or actual capital amounts for each year; and
- Columns (l) through (s) identify the projected or actual O&M amounts for each year.

Page 2 provides an analysis of total actual and projected enhancements, total incremental annual worklist of enhancements, total annual demand, total Company cumulative worklist, and gas allocation cumulative worklist. Specifically:

- Column (a) identifies the categories used for analysis, where total amounts include both capital and O&M;
- Columns (b) through (i) identify the projected or actual amounts by year; and
- Column (j) identifies the projected amounts for the test year.

Total gas Actual and Projected amounts are derived from Exhibit A-24 (SHB-9), page 1, which are the source for the figures indicated. Total Company incremental annual worklist, Exhibit A-25 (SHB-10), is defined as the total Company cost of planned enhancement requests received in the year indicated. Total gas allocation incremental annual worklist provides the gas allocation of the total Company incremental worklist. Total gas annual demand is defined as the total fulfilled and unfulfilled enhancement demand for the year, calculated by the sum of total gas Actual/Projected spend and Total Gas Allocation Incremental Annual Worklist. Total Company Cumulative Worklist is defined as the year-over-year increase of unfulfilled enhancement requests. Total Gas Allocation Cumulative Worklist provides the gas allocation of the Total Company Cumulative Worklist.

Q. What is the purpose of Enhancements investments?

A. Enhancements are smaller, short-cycle technology efforts to implement new or improved functionality and provide the flexibility needed to respond to rapidly changing business and customer conditions. Enhancement requests typically emerge from new or changing business conditions, compliance requirements, customer feedback, automation efforts, waste elimination efforts, and other improvement ideas. Enhancements benefit customers and the Company through cost savings, cost avoidance, productivity improvements, safety improvements, efficiencies, mandated regulatory changes, and improved customer experience.

Q. Please describe Exhibit A-25 (SHB-10).

A. Exhibit A-25 (SHB-10) is the Enhancement Worklist Detail Report. It provides a summary of the Enhancements queue of work requests. Specifically:

- Column (a) provides the Enhancement open date, internally referred to as the Open Date of the request;
- Column (b) identifies the Number, which is used to internally track the lifecycle of the Enhancement request;
- Column (c) identifies the Type of request;
- Column (d) provides a Description of Work;
- Column (e) provides the Work State of Submitted, Screening, Qualified, and Approved;
- Column (f) provides the Portfolio that has requested the enhancement;
- Column (g) identifies the Associated Application, which is internally referred to as the Configuration Item, and is the application that will be changed with the Enhancement;
- Column (h) identifies the internal Requestor Department;
- Column (i) provides the Total Estimated Hours, which reflects the planning estimate of work hours entered prior to the start of work request; and
- Column (j) provides the estimated Cost.

Q. How does the Company track and manage enhancements?

A. The Company actively maintains a worklist of enhancements, Exhibit A-25 (SHB-10). Each enhancement is tracked in detail from idea to completion including steps for value justification, estimation, prioritization, final funding approval, execution, and closure. For an enhancement to seek funding approval, it must be qualified with a cost estimate and benefits to ensure the enhancement is ready for execution. Once approved for funding in cross-functional business team reviews, the enhancement is scheduled. When the enhancement begins execution, the status for enhancement records is updated by enhancement request coordinators through closure. This provides the Company with an auditable tracking method for every enhancement request.

Q. Please explain the historical demand for enhancements and the Company's projection for future enhancement demand.

A. The demand for enhancement efforts has grown an average of 49% over the past three years because of the increased need for automation efforts, focus on waste elimination and cost optimization, additional functionality requests to optimize aging applications, and enhanced functionality requests for newly implemented technology.

As of October 2024, the Company has a worklist (Exhibit A-25 (SHB-10) of 639 requests Company-wide to improve multiple applications and systems. This well-known worklist demonstrates the high volume of demand for smaller technology efforts. Despite exceeding the projected spend in several previous years, the Company is unable to keep up with the growing demand for enhancements, as shown on Exhibit A-24 (SHB-9), page 2. The projected Total Gas Allocation Cumulative Worklist (Demand) for the test year is $7,577,721 (Exhibit A-24 (SHB-9), page 2, line 7, column j), while the Company is projecting $7,416,712 of Total Gas Projected Spend (Exhibit A-24 (SHB-9), page 2, line 2, column j). To recognize this increasing demand and better project Enhancement costs, the Company is projecting these costs by determining incremental enhancement demand for 2025 and 2026 based on a known worklist, plus applying a combination of historical demand and historical spend. The projected level of demand still outpaces projected spend, as indicated above.

Q. What methods is the Company using to ensure projected enhancement expenditures and expenses in the test year are reasonable and prudent?

A. The Company is using two methods to validate enhancement demand expenditures and expenses in the test year: (1) three-year historical average and (2) total cumulative demand. For the three-year historical average method, the Company calculated the actual three-year historical average for 2022-2024 of $4,848,979 plus know incremental work of $3,117,727 ($7,966,706) and compared it to the projected Test Year enhancement expenditures and expenses of $7,416,712. This validates Test Year projections are in line with historical spending and known incremental work. Then for the total cumulative demand method, the Company compared the Total Gas Allocation Cumulative Worklist amount of $7,577,721, in Exhibit A-24 (SHB-9), page 2, line 7, column j, to the projected Test Year enhancement expenditures and expenses of $7,416,712. This comparison validates these projections are in line with the projected demand.

Q. Please further explain the Company's calculation for the cumulative worklist amount.

A. Projections for the total cumulative worklist in 2025 and 2026 are based on the three-year average annual increase to enhancement demand. As indicated, cumulative enhancement requests grew at an average annual rate of 49% over the past three years. As a result, the cumulative worklist for enhancements (Exhibit A-25 (SHB-10)) continues to grow year over year, as depicted on Exhibit A-24 (SHB-9), page 2, row 7. Validating the projected Enhancement spending based on a known worklist and a three-year historical average of actual spend is an indication that the Company's test year projected spend of $7,416,712 is reasonable and prudent.

Q. Please explain the Enhancements projects.

A. The following are the Enhancements projects:

- The **Enhancements - Capital** and **Enhancements - O&M** requires the capital and O&M in the test year as described in the table below.
    - **Description:** These projects will utilize capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included with capital projects to complete expense activities associated with capital enhancements.
    - **Problem Statement:** As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.
    - **Objectives:** The value of software enhancements lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the respective business areas.
    - **Scope:** The scope of application enhancements encompasses: (1) making necessary system changes; and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide new functionality for business areas represented by each program.
    - **Alternatives:** Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of

representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

Specific spend requirements for each Enhancement project are indicated in the table below.

Project	**Projected Test Year Capital**	**ROM Adjusted Test Year Capital**	**Test Year O&M**
Product Family Enhancements-Corporate-Capital	$968,872	$0	$164,000
Product Family Enhancements-Corporate-O&M	$0	$0	$176,642
Product Family Enhancements-Customer-Capital	$1,928,428	$0	$287,903
Product Family Enhancements-Customer-O&M	$0	$0	$161,549
Product Family Enhancements-Electric & Gas Shared-Capital	$266,622	$0	$24,296
Product Family Enhancements-Electric & Gas Shared-O&M	$0	$0	$68,261
Product Family Enhancements-Gas-Capital	$1,382,825	$0	$165,688
Product Family Enhancements-Gas-O&M	$0	$0	$239,401
Product Family Enhancements-Application Platform Services-Capital	$300,361	$0	$103,023
Product Family Enhancements- Application Platform Services -O&M	$0	$0	$53,515
Product Family Enhancements-Infrastructure Platform Services-Capital	$207,502	$0	$66,113
Product Family Enhancements-Infrastructure Platform Services-O&M	$0	$0	$109,219
Enhancements-Security-Capital	$287,031	$0	$53,891
Enhancements-Security-O&M	$0	$0	$123,761

Digital Foundations and Capabilities Projects

Q. Please explain the Digital Foundations and Capabilities projects.

A. Below are the Digital Foundations and Capabilities projects:

- The **Data & Analytics Platform Rationalization** project requires $1,228,844 in capital ($983,075 ROM Adjusted Capital) and $240,126 in O&M in the test year.
  - **Description:** This project will optimize the Data & Analytics system landscape by creating connections, migrating data into Data Lake 2.0 ("DL 2.0"), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems including SingleStore Data Lake ("SSDL"), SAP Business Warehouse ("BW"), BOBJ, Native HANA, the BW Portal, and SAP Business Objects Data Services ("BODS") creates value by reducing the total cost of ownership associated with maintaining and supporting legacy systems.
  - **Problem Statement:** The IT Data & Analytics legacy systems (SSDL, SAP BW, BOBJ, Native HANA, the BW Portal, and BODS) are outdated, inefficient, and becoming duplicative in nature with the introduction of DL 2.0. If these legacy systems are not retired, they will continue to cost the Company money as major investments are needed to maintain and support them.
  - **Objectives:** This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources.
  - **Scope:** The project scope includes: (1) the assessment of the existing Data & Analytics platforms including SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organization change management; and (7) the retirement/decommissioning of the legacy platforms and applications.
  - **Alternatives:** Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company's cloud strategy. (2) Lift and shift these on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the

work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces. The alternative to migrate all data sources to DL 2.0 and retire legacy systems was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.

- The **Digital-Hybrid Cloud and Data Center Migration** project requires $93,044 in capital and $35,979 in O&M in the test year.

  - **Description:** This project will optimize data center assets and asset replacement project purchases by migrating or retiring applications out of existing Company and co-location data centers into cloud services, reducing operational costs for running IT services and leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services.

  - **Problem Statement:** The technology currently deployed in the Company's data centers meets many customers' needs today. However, the pace of digital transformation is increasing rapidly, and requirements for applications are evolving faster than the technology in the Company's data centers can respond in a cost-effective manner. These data center constraints lead to longer implementation times, missing capabilities, or reduced functionality in the applications that the Company can deploy.

  - **Objectives:** This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective combination of data centers and public cloud services. Specifically, by migrating applications to cloud services, the project will: (1) reduce capacity, hardware maintenance, and security device costs at the co-location data center; (2) reduce hardware maintenance and security device costs at the production data center; (3) enable the ability to scale infrastructure quickly up or down without costly up-front hardware purchases; (4) reduce application risk through cost-effective, scalable infrastructure redundancy and availability; (5) reduce ongoing server and storage asset replacement costs; (6) reduce ongoing networking equipment replacement costs; (7) reduce operational support costs; and (8) enable the use of a vast array of cloud services to support Company applications.

  - **Scope:** The project scope includes: (1) promoting the robust main co-location data center to become the primary data center for on-premise IT services; (2) demoting the Company's production data center to the disaster recovery data center for on-premise IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premise to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying base infrastructure to allow each location (on-premise or in cloud) to function independently; (7) deploying cloud and on-premise cost management tooling and processes; (8) simplifying and optimizing backup and disaster recovery resources and processes using cloud services; (9) implementing additional automation for application deployment and management; (10) changing the operations model for support of cloud-based applications; (11) educating and increasing the skills of IT and other employees in leveraging public cloud services; and (12) transforming IT to become the broker of cloud services for the Company.

- **Alternatives:** Alternatives considered included: (1) migrating to public cloud services faster. This alternative was not chosen because the Company's ability to absorb new technologies coupled with the investments the Company has already made in data center equipment would prevent a faster move from being efficient and effective, introducing additional financial risk; (2) migrating to public cloud services slower or not at all. This alternative was not selected because delaying public cloud services and capabilities coupled with requiring an extension of the life of existing data center equipment creates increased financial and operational risk; and (3) contracting with an outside vendor to provide cloud services to run applications for the Company. This alternative was not selected because industry information shows the option as not yet cost effective or not providing a maturity level that the Company would be able to easily consume with limited in-house experience and expertise in public cloud. The alternative to migrate to a hybrid cloud and data center model was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.

- The **OT Datacenter Migration** project requires \$1,801,259 in capital (\$1,441,007 ROM Adjusted Capital) and \$ 716,473 in O&M in the test year.

  - **Description:** The OT environment consists of systems supporting the control and monitoring of electric grid, electric generation, gas compression, and natural gas pipeline. These systems are critical for safe and reliable natural gas and electric delivery. The OT Datacenter Migration project enhances the Company's capabilities by co-locating to an enhanced datacenter at a vendor facility.

  - **Problem Statement:** The Company's current datacenter for the OT environment needs modernization and relocation from the Parnall Data Center. The current location is not the preferred location to house servers and systems critical to the control of the Electric Grid or Gas Pipeline due to the close proximity to a railway system. The climate conditioners in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns. The location of the datacenter in the basement of the Parnall building is nearby to the main water piping for the building. There have been instances of water infiltration in the past.

- **Objectives:** This project creates value for the Company by significantly strengthening capabilities through: (1) mitigating legacy physical and location risks at the current Parnall site; (2) migrating the OT infrastructure to a modern, highly secured environment with redundancy in climate conditions; and (3) better datacenter facilities support with a guarantee of redundant power.

- **Scope:** The scope of the project includes: (1) migration of the OT environment from the Parnall Data Center to a co-located vendor data center; (2) re-validation of the OT Production and Disaster Recovery procedures once migration is completed; (3) migration of IT systems required for supporting the OT environment; and (4) decommission the existing OT environment from the Parnall location.

- **Alternatives:** The Company performed an analysis of alternatives to expand capabilities as well as address constraints and risks: (1) Remain at the current Parnall Data Center; (2) migrate OT environments to the Cloud; and (3) relocate to a third-party co-location facility. Current industry best practices do not recommend migration of OT environments to the cloud. The co-location vendor provides the building, cooling, power, and physical security the Company lacks for its servers, storage, and other computing and networking equipment at the current Parnall location. Based on the analysis, the Company decided to implement the third alternative.

• The **Spatial Asset Management** project requires $37,398 in capital ($29,918 ROM Adjusted Capital) and $6,635 in O&M in the test year.

- **Description:** This initiative will implement SAP's Spatial Asset Management module. It will allow users to view assets, notifications, and orders geospatially using a map. The module will allow the Company to create and maintain asset maintenance plans for each segment of the Company's gas and electric distribution networks (linear assets). The Company will create linear assets as technical objects (such as functional locations and equipment) and store linear data. The Company will enable creation of maintenance plans for these technical objects which result in notifications, maintenance orders, and measurement documents. The Company will enable monitoring the condition of linear assets, identify where there is damage or a defect (using the start point and end point and offset), and manage all types of maintenance tasks (planned, unplanned, and preventative).

- **Problem Statement:** Currently, the Company lacks spatial visualization and spatial awareness of work and assets impacting requirements for first time quality and impacting the ability to plan, bundle, and execute nearby work. The lack of a linear asset management capability affects the full work management value stream resulting in overproduction of asset maintenance activity such as assessments, surveys, and inspections.

- **Objectives:** This project creates value for the Company by (1) providing capability in SAP to view assets, notifications, and work orders on a map; (2) providing location awareness in SAP for assets and work; (3) establishing linear asset management capability in SAP for gas and electric delivery networks; and (4) enabling end-to-end map-based workflows.

- **Scope:** The scope of this project encompasses implementation in SAP of the Spatial Asset Management module.

- **Alternatives:** Alternatives considered include: (1) Implement a cloud-based individualized asset integration between GIS and SAP. This alternative was not selected as it proves ineffective in addressing needs of the end-to-end work management value stream while increasing the technical footprint of customization. There are also performance concerns with cloud to on-prem integrations; (2) Implement work group centric approaches to viewing work on a map. This alternative was not selected as it does not support standard operation through the entire work management value stream; (3) Do nothing. This alternative was not selected as this would result in increasing costs and inefficiencies in gas and electric work management; and (4) The alternative to implement the Spatial Asset Management module in SAP was chosen as it expands use of a core technology investment, supports current investment in the Company's work management value stream, and is compatible with our GIS technology.

Q. Please explain the SAP HANA Database Migration project.

A. The SAP HANA Database Migration project has the following synopsis:

- The **SAP HANA Database Migration** project requires $88,339 in capital and $25,464 in O&M in the test year.

  - **Description:** In preparation for SAP's planned end of support for its Business Suite product in 2027, the Company will migrate its existing SAP databases from Oracle to SAP HANA in advance of the required move to S/4HANA.

- **Problem Statement:** The Company's SAP applications currently utilize Oracle's relational database management system as their underlying database storage technology. SAP has informed its customers that standard support for its legacy Business Suite (aka ECC) product will end in 2027, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the company will migrate all of its SAP databases off of Oracle and onto SAP HANA.

- **Objectives:** This project lays the groundwork for the Company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027.

- **Scope:** Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures, and tools required to manage the newly migrated SAP HANA applications.

- **Alternatives:** Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering no other options for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform a direct migration from SAP Business Suite on Oracle to S/4HANA. A direct migration to S/4HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application's functionality would change simultaneously, so this alternative was not selected. (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S/4HANA. It will also require the Company to accept significant risk due to the fact that SAP security patches, application patches and upgrades will not be available upon termination of the SAP maintenance agreement. (3) Migrate to SAP's SaaS implementation of S/4HANA. This alternative was not selected because an S/4HANA SaaS migration is a much more disruptive option as the Company's business processes must be adjusted to accommodate functionality differences between ECC and S/4HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. The selected alternative to migrate the SAP databases to HANA prior to implementing S/4HANA gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process changes required with S/4HANA.

Q. What is the Company's migration timeline for the SAP HANA Database Migration project?

A. The Company initiated the SAP HANA Database Migration project in April 2023 and is anticipated to be completed by December 2025. The migration will be staggered across 2024 and 2025. In 2024, the Company will migrate ancillary systems to HANA to gain valuable insight from these migrations and address any technical issues before migrating the ECC in 2025. This will also provide time to conduct mock migrations for ECC, which will help minimize downtime.

Q. Please explain the SAP S/4HANA Implementation project.

A. The SAP S/4HANA Implementation project has the following synopsis:

- The **SAP S/4HANA Implementation** project requires [redacted] in capital ([redacted] ROM Adjusted Capital) and [redacted] in O&M in the test year.
  - **Description:** This project will modernize the Company's current ERP SAP solution. Upon completion, the solution will provide enhanced functionality across several business areas while providing a supported and secure platform capable of business transformation**.**
  - **Problem Statement:** The current SAP ERP system will reach the end of mainstream vendor maintenance on December 31, 2027. Operating the system beyond the end of support date creates significant risks to comply with regulatory mandates, perform core customer supporting business operations, and apply the latest security patches that are critical for cyber protection against customer and employee data breaches. In addition, an unsupported platform limits improvement of operational efficiency and maintaining the stability, reliability, and security of the system.
  - **Objectives:** The S/4HANA program will position the Company for business transformation by enabling it to (1) provide and maintain

capabilities for protection of sensitive customer and employee data; (2) provide enhanced system stability and reliability needed in a 24x7 business by significantly reducing system maintenance outages; (3) mitigate the regulatory and operational risks of running critical business processes on an unsupported platform; (4) implement simplified workflows and standardized processes by reducing customizations; and (5) use in-memory computing with embedded real-time analytics to make smarter, faster decisions.

- **Scope:** The project scope includes (1) Migrating the current SAP ERP solution to the latest S/4HANA solution. This includes (a) moving to the latest version of the software, (b) migrating existing data to the new S/4HANA data model, (c) connecting interfaces from other systems into S/4HANA, (d) using newer user interfaces available in S/4HANA where feasible, (e) setting up users and user access in the new system, (f) migrating existing reports and analytics or replacing them with new in-built reports and analytics in S/4HANA, and [redacted] (2) Enabling an architecture that minimizes downtime for system maintenance activities. (3) Implementing solutions where existing SAP ERP functionality is not available in S/4HANA. (4) Implementing a foundational "clean core framework." This requires minimizing or remediating custom code and utilizing SAP customization best practices in the new version. These best practices will decouple the core SAP software from Company-specific customizations, hence making it "clean." This clean core framework is expected to reduce the effort and cost of upgrading SAP in subsequent releases.

- **Alternatives:** An analysis was completed that included key industry input, feedback from business areas across the Company, technology leaders, and subject matter experts. This presented the organization with several alternatives, including the following: (1) Postpone the decision and stay on the current version. This would require purchasing the extended maintenance until 2030 due to the current mainstream maintenance expiring in December 2027. A skill shortage is anticipated as SAP customers scramble to meet the 2030 deadline. Delaying our decision to migrate to S/4HANA would put the Company at a higher risk of securing those high-demand skilled resources. Staying on the current version beyond 2030 with third-party support would limit the Company's ability to continuously improve operational efficiency and maintain the stability, reliability, and security of the system. This alternative was not selected because of the additional cost and risk, and the inability for the Company and its customers to enjoy any added benefits or new application features. (2) Eliminate SAP and use multiple best of breed solutions in the various business areas. (3) Eliminate SAP and implement a new ERP solution. SAP is currently used across the Corporate, Work and Asset Management, and Customer areas. There are very limited options for a single ERP system that provides all three areas of functionality. The current SAP system has over 100 satellite systems and around a thousand interfaces. Non-SAP alternatives may not work with current satellite systems, requiring the replacement or significant remediation of those satellite systems. These non-SAP alternatives would require a much larger change management initiative, significant reskilling of technical resources, and retraining of people across the Company who have become familiar with SAP over the last 16 years. Alternatives (2) and (3) are more expensive, complex to implement and support long-term, therefore were not chosen. (4) Migrate to the latest S/4HANA solution before the end of 2030. This option was chosen because it mitigates risks and provides a supported and secure platform capable of business transformation.

Q. Describe the deployment approach the Company will utilize for the SAP S/4HANA Implementation project.

A. The Company will deploy the migration to the new S/4HANA solution in phases to reduce the risk of operational impact to customers and co-workers. The Company will adopt SAP's standard Activate methodology for the deployment approach.[3] The Activate methodology includes six phases: Discover, Prepare, Explore, Realize, Deploy, and Run/Adopt. The Discover, Prepare and Explore phases result in the design, which is then built, tested, and deployed in the Realize, Deploy, and Run/Adopt phases. The approach is to design the system holistically, meaning the Discover, Prepare, and Explore phases will cover all modules of SAP, including Finance, Supply Chain, HR, Work Management, and Customer. This ensures the system is designed optimally from end to end. Once the design is complete, the Company will conduct multiple iterations of the Realize, Deploy, and Run phases to deploy functional modules in a staggered capability deployment approach.

[3] Available at https://learning.sap.com/learning-journeys/discovering-sap-activate-implementation-tools-and-methodology/describing-sap-activate

Q. Please explain the different S/4HANA migration alternatives considered.

A. The Company considered three migration alternatives: (1) Build a new SAP system without using any existing customizations, configurations, processes, or data (Greenfield); (2) Upgrade the existing SAP system, retaining existing customizations, processes, and data, then remediate errors that arise in the upgrade process in a series of iterations (Brownfield); and (3) Adopt a hybrid strategy, building a new SAP system, while selectively migrating critical data and process from the existing system (Bluefield).

Q. Which S/4HANA migration approach has the Company selected?

A. The Company has selected the hybrid or Bluefield approach for the S/4HANA Implementation project.

Q. Why did the Company select the Hybrid, or Bluefield, migration approach for the S/4HANA Implementation project and not the others?

A. The Company chose the Hybrid, or Bluefield, approach because it offers the best balance of lower risk and cost[4]. While the Greenfield option provides lower total-cost-of-ownership and faster time-to-value for implementations that want to shed a lot of legacy customizations and start afresh, this is not fully the case for the Company because the current system has many essential customizations in the customer billing and employee payroll areas that will need to be rewritten in the new system with this approach. Rebuilding customizations introduces significant risk and cost. Similarly, the Brownfield approach could provide a shorter project timeline by migrating all the current customizations and processes. However, this approach is not preferred in the Finance, Supply Chain, and Work Management areas where the current system has a lot of custom processes, workflows,

[4] Available at https://www.leanix.net/en/wiki/tech-transformation/s4hana-greenfield-vs-brownfield-approach

enhancements, and interfaces that are suboptimal compared to the standard best practice processes that come in S4/HANA. The Brownfield approach is also not preferred because the processes and data model in Finance and Supply Chain have changed significantly. Upgrading current customizations to the new system would not be easy and rewriting them would be expensive and increase risk. This would result in a new system that does not conform to SAP's clean core approach and would be expensive to upgrade in the future. Therefore, the ideal approach is a combination of the two where the new system adopts a Greenfield approach for Finance, Supply Chain and Work Management, and a Brownfield-like approach for Customer and Payroll.

Q. Why is the Company undertaking the expense and effort of migrating to the SAP S/4HANA version at this time?

A. Migrating to the SAP S/4HANA version is crucial for the Company because the mainstream support for our current SAP version ends in December 2027. After evaluating the project, the Company determined it will take approximately three years to complete. Assuming the Company begins the project in 2025, the timeline will extend into 2028, requiring the Company to purchase extended SAP support for 2028. It is important to note that extended support for the Company's current SAP version is only available until 2030.

Q. Will the Company's SAP systems face an increased risk of cyber-attacks if the S/4HANA project is not executed?

A. Yes. The Company's SAP systems will face increased risk of cyber-attacks if the S/4HANA project is not executed, because SAP has stated that after maintenance ends, standard patches will no longer be available for SAP customer-specific maintenance, leaving the Company's SAP systems vulnerable to emerging threats from bad actors exploiting known vulnerabilities.[5]

Q. Please explain whether the Company's SAP systems will continue to operate if the S/4HANA project is not executed?

A. The Company's SAP systems will continue to operate with significant risk for an indeterminate period of time if the S/4HANA project is not executed. SAP will not support the Company's current SAP version after December 2027, when the mainstream maintenance ends. After this period, the risk of operational disruptions will increase significantly due to the lack of a Service Level Agreement with SAP, and there will be no guarantee that SAP resolve any new issues that arise.

Q. How did the Company develop the cost estimate for the SAP S/4HANA Implementation project?

A. The Company developed the cost estimate for the SAP S/4HANA Implementation project with the support of an independent third party that specializes in preparing for S/4HANA upgrades. The cost estimate consists of labor, contractor, software, and non-labor costs.

The labor and contractor cost estimates were derived as follows:

- First, the phases of the project were laid out in a timeline based on the phased deployment approach and Hybrid migration approach, both previously described in my testimony.
- Second, the high-level scope was identified, including the processes, pain points, customizations, integrations, roles, and data volumes that need to be migrated to S/4HANA.
- Third, the effort for the design and subsequent phases were translated into the number of hours and resources required for each phase. The resources are further broken down into roles and number of each role.

[5] Available at https://support.sap.com/en/my-support/knowledge-base/security-notes-news.html?anchorId=section_370125364

  - Lastly, the resource estimates were assumed to be a mix of 30% internal employees and 70% external contractors. The Company then applied an average resource rate based on internal and external resources to calculate the cost estimate. For certain activities, the resource estimate was derived using a percentage of the overall effort based on best practices, e.g. program management and quality management.

- The software cost estimate was based on indicative Bill of Material ("BOM") from SAP.

- The non-labor cost estimates are based on business expense, and labor overheads based on projected internal labor and external contractor costs to support the project.

Finally, the Company conducted a comparison of peer utility overall cost estimates and duration for their S/4HANA implementation projects to validate the Company's overall cost and duration estimate was reasonable.

Q. Why is this SAP upgrade more costly than the Company's previous upgrades?

A. This SAP upgrade is more costly than the Company's previous upgrades for several reasons. First, the latest SAP S/4HANA version improves business processes, requiring the Company to thoroughly evaluate these best practices against existing processes. This evaluation is crucial in determining adoption and adds to the overall project cost.

Second, migrating data to the new system involves mapping, transforming, and testing data elements required by S/4HANA's new data model. Third, the Company must re-evaluate and update user access because the system controlling access permissions has changed in S/4HANA. Fourth, the existing solution has customizations that cannot be moved to the new system as-is due to the differences in business processes, data model, and permissions. Finally, SAP recommends customers adopt a "clean core" approach when customizations are necessary. This approach moves the customizations outside the core product, which makes future upgrades easier. This requires the Company to perform a detailed evaluation and remediation of existing customizations.

Q. Would it be more cost-effective for the Company to replace its SAP systems?

A. No. It would not be more cost-effective for the Company to replace its SAP systems. This would require re-engineering the entire SAP system to a new solution, assuming that the current system could be replaced with a single replacement. It would require significant effort to re-skill the Company's co-workers, re-engineer business processes, re-implement the system, and integrate the new system with all the systems currently interfacing with SAP. The Company currently has more than 1,000 interfaces to SAP. Replacing SAP with multiple systems would be more costly and introduce additional risk due to the complexity of managing multiple disparate solutions. The Company would need to develop integrations between systems like Finance, Supply Chain, Work Management, and Customer. These integrations are inherent in an integrated solution such as SAP.

Q. Is the Company requesting any special rate-making treatment to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project?

A. Yes. The Company is requesting to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project over a 15-year asset life. This software asset will provide significant value and functionality over an extended period, as it is deeply integrated into the Company's business processes, and there is a substantial investment in its development and integration. The benefits of continuing to use the existing software outweigh the costs of transitioning to new software sooner than 15 years. This approach will also benefit customers by spreading these costs over 15 years to minimize the impact on customer rates.

Q. Please describe Confidential Exhibit A-26 (SHB-11).

A. Confidential Exhibit A-26 (SHB-11) is the IT S/4HANA Cloud Implementation Costs balance for Gas and Common investments for the projected 13 months ending October 31, 2026. It provides a summary of the gas allocation of projected IT Department investments expenditures. Specifically:

- Column (a) provides the balance category;
- Columns (b) through (n) provide each month's ending IT S/4HANA Cloud Implementation Costs balance; and
- Column (o) provides the 13-month average of columns (b) through (n).

Q. Please describe the purpose of Confidential Exhibit A-26 (SHB-11).

A. The Company has identified cloud computing as a viable alternative for several technology solutions associated with the SAP S/4HANA Implementation project. As discussed previously, the Company is requesting to amortize the cloud implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA Implementation project over a 15-year asset life and adjusting working capital. Cloud implementation costs are projected based on the planned implementations of the SaaS solution associated with the SAP S/4HANA Implementation project. This working capital adjustment is provided by Company witness Rayl on Exhibit A-12 (HLR-34), Schedule B-4.

Q. Is the Company requesting any additional special rate-making treatment for the SAP S/4HANA Implementation project's Investments O&M expense?

A. Yes. The Company is also requesting to defer the Investments O&M expense associated with the SAP S/4HANA Implementation project and recover the expense over the life of the asset. This approach will benefit the customers by spreading these costs over the life of the asset to minimize the immediate impact on customer rates. This proposal will be discussed further in the direct testimony of Company witness Heidi J. Myers.

Q. Please explain the IT Operations Management – Service Operations project that is new in this case in 2023 and 2024.

A. The IT Operations Management – Service Operations project has the following synopsis:

- **Description:** This project will implement an application service mapping tool to effectively manage business-critical services through identification of infrastructure components and application interactions. This tool automates the mapping process to create a complete, up-to-date, and accurate record of the mapped application service in the Database. Application service mapping works hand-in-hand with asset discovery, building on discovered infrastructure data to identify all the assets that support a service, and along with their service-specific relationships.

- **Problem Statement:** As the IT systems steadily increase in complexity and evolve faster than the IT organization can respond to system issues in an optimized and cost-effective manner, the current configuration of the system does not provide the clarity needed in order to understand how the infrastructure interacts with the applications within the IT System it supports and in order to respond to emergent IT incidents in the most rapid and cost effective manner. These constraints can lead to lengthy response and implementation times; negligible or ineffective resolutions; reduced functionality; and elongated outage times in the infrastructure and applications in the system.

- **Objectives:** This project will create value for the Company by mapping critical application services through discovery of the underlying infrastructure associated with application services and its relationship to parent business applications. Specifically, by creating application service maps, this project will: (1) increase visibility and understanding between IT infrastructure and Configuration Items; (2) improve accuracy through real-time, automatically updated infrastructure and component changes; (3) reduce IT Subject Matter Expert time on emergent IT issues; (4) Utilize IT Service Management processes; and (5) Reduce downtime by identifying dependencies and impact analysis.

- **Scope:** The project scope includes: (1) implementation of on-premise application service maps which have significant business impact; and (2) establishment of process roles needed to support service maps built.

- **Alternatives:** Alternatives considered included: (1) Choose an alternate IT Operations Management System with Cloud capabilities. This alternative was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not chosen as there would be a correlation gap between application services and the underlying infrastructure and would not address the ever-increasing resolution costs. (4) Develop and implement an on-premises service mapping and process solution. This alternative was chosen due to the value in IT Operations Management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can utilize the Configuration Management Database ("CMDB") and work hand-in-hand with asset discovery.

Q. Please further describe the value of the IT Operations Management – Service Operations project.

A. The IT Operation Management – Service Operations project will reduce the time for resources to identify and troubleshoot critical incidents by 30%, which will result in avoided labor costs.

<u>**Security Projects**</u>

Q. Please explain the Security projects.

A. Below are the Security projects:

- The **Business Continuity - Program Management Tool** project requires $33,092 in O&M in the test year.
  - **Description:** The Business Continuity Program Management Tool is critical for successful and effective Business Continuity, Disaster Recovery, and Emergency Management Programs. The software tool will provide automation, enhance the Company's incident management processes, establish critical linkages between departments and essential functions they support, and will perform necessary analysis before, during, and after a disruption that allows for the efficient response to minimize downtime.
  - **Problem Statement:** The current business continuity and disaster recovery program management tool does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. The current tool limits automation opportunities which result in manual workarounds. The lack of capability affects reporting, upstream/downstream impact mapping, Incident Command System ("ICS") documentation automation, and user administration.

- **Objectives:** This project will create value for the Company by: (1) maintaining and/or promptly recovering critical processes and associated essential functions that, if disrupted, would present significant impact to the Company and customers; (2) limiting business and community impact while providing a critical energy service; (3) prioritization of the recovery of critical processes and resource allocation during a business continuity incident(s); (4) providing a consistent, organized, and expedient response process (ICS) that is flexible to meet the needs of any incident, regardless of severity or scope; (5) providing a mechanism for identifying restoration gaps between critical business processes and IT recovery capabilities; (6) reducing or eliminating human error and waste; and (7) improved and more efficient user experience.

- **Scope:** The project scope includes: (1) framework for the development and maintenance of Business Continuity, ICS, and Disaster Recovery Plans that are effective and easily accessible during an event; (2) automation for reporting to track status, to measure effectiveness and maturity of the program (Business Continuity, Emergency Management, Disaster Recovery Programs) and to facilitate effective response; (3) program management tools to monitor required program deliverables; (4) template for developing and maintaining site hazard assessments; (5) dependency mapping of critical business processes and IT applications; and (6) integrated business impact analysis process.

- **Alternatives:** Alternatives considered include (1) continue to use Castellan (current Disaster Recovery tool). This alternative was not selected because it currently does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. (2) Revert back to manual process. This alternative was not selected because the manual process is time consuming and leads to human struggle and duplicative work. A previous KPMG Audit of the Business Continuity Program indicated the need for interdependency mapping and a software tool is the best way to accomplish this. (3) Implement a best-in-class Cloud SaaS solution. This alternative was selected because there are many SaaS solutions that fit the needs outlined above. The final application will be determined after a Request For Proposal is issued and a vendor is selected in the project plan phase.

- The **Forward Web Proxy Services** project requires $1,173,788 in capital ($939,030 ROM Adjusted Capital) and $149,967 in O&M in the test year.

  - **Description:** This project will replace the current web proxy service platform with a new platform. A web proxy service is a type of proxy server that sits between a client and the internet. It acts as an intermediary that evaluates, modifies, and forwards the client's requests to the destination web server. This service offers many benefits for the Company such as advanced filtering. Advanced filtering in a forward web proxy service can filter out unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of attacks such as ransomware.

- **Problem Statement:** The Company currently leverages an existing vendor platform for web proxy services that has been in existence since 2021. Since the implementation of the platform, it has caused ongoing operational issues related to web filtering and connectivity. When there is a degradation of service, Company employees and contractors are unable to access internet or cloud-based resources. As the Company continues its cloud and SaaS journey, it is imperative to provide consistent access and communication, while still protecting the Company from cyber threats.

- **Objectives:** This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilizing technology to enable the Company to handle all types of different workloads from varying geographic locations and is highly available; (3) using a mature and scalable web proxy service provider; and (4) providing Zero Trust by continuously verifying every connection request.

- **Scope:** The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; and (3) potentially changing SaaS cloud vendors.

- **Alternatives:** The Security team did extensive research on alternative web proxy services solutions. Alternatives considered include: (1) continue to use and maintain the current web proxy services platform. This alternative was not chosen due to the consistent operational issues with the platform that make it unreliable. The result of an unreliable system means that employees and contractors are unable to access business critical services such as email, Teams, ServiceNow, and SharePoint Online; (2) route all internet traffic through the Company's corporate data center. This alternative was not chosen because the capabilities of firewalls are not as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) replace current system with modern vendor platform for web proxy services. The option that was chosen is to replace the current solution with a new system. This option was chosen because it offers additional features such as browser isolation (the ability to contain web pages so that the web page cannot affect the client workstation) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation, the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's capabilities.

- The **Physical Access Management and Alarm Response** project requires \$846,948 in capital (\$677,559 ROM Adjusted Capital) and \$101,685 in O&M in the test year.

  - **Description:** The project will replace the Company's Physical Access Management System to establish a centralized platform that manages user identities, authenticates users, authorizes access, and audits user activities. The intent of this project is to consolidate and modernize the Company's physical security systems that will enable enhanced security monitoring to prevent unauthorized entry into sensitive corporate areas while providing increased flexibility to the Company's valued employees and contractors.

  - **Problem Statement:** The Company's Security Fusion Center (the Fusion Center is the Company's combined physical and cyber security operations center) is experiencing operational issues with the current physical access management system. The installation is out of date and causes inconsistent behavior when given tasks by automations within the Company's Identity Management solution. Frequent issues have been reported related to frozen jobs in the Company's existing access management solution due to the current system's database. This results in significant waste in the form of (1) waiting, the business partner is waiting much longer than they should have for the system to process their request as un-freezing jobs is a manual process; (2) lost productivity, that waiting can cause for the business partner as it can either prevent them from accessing sites they need, or slow them down unnecessarily while they work with others to be escorted; (3) rework, because frozen jobs do not always run correctly when unfrozen, meaning the business partner has to resubmit their request and/or Identity Operations has to do additional work to satisfy the original request; and (4) alarms can cause a frozen state that impact system stability and reduces security visibility as a result. Not moving to new technology also carries a growing risk of outright system failure which could result in unauthorized physical access and/or impact the Company's ability to efficiently function. The current installation of the physical access management system and the Company's current card readers do not support next generation physical access control methods, such as digital ID. This prevents the Company from adopting new methods and practices that can lower costs and improve control and responsiveness. All employees, contractors, staff, and visitors are impacted by the problem.

  - **Objectives:** This project creates value for the Company by: (1) developing an alarm and event monitoring system, which will enable seamless orchestration of system alarms and cameras; (2) adding automation that will streamline remediation processes and orchestrate camera operations for efficiency; (3) refining access revocation and badge access management to ensure only authorized personnel have entry privileges; and (4) introducing new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company's facilities.

- **Scope:** The project scope includes modernizing the Company's current physical access control system, badge system, badge access hardware and firmware, and all 3000 card readers across facilities and assets. This will require modernization of all physical badge access readers and the implementation of hardware and software necessary to run the physical access control system. In addition, there will be substantial automation and integration between the security orchestration solution and the physical access control systems to realize the full benefits of this initiative.

- **Alternatives:** Alternatives considered were: (1) Keeping the current physical access control system and processes as-is. This alternative was not selected as the current platform is outdated, increasingly expensive to support, and does not include modern capabilities, such as digital IDs. It also does not reduce waste, cost, and it does not improve speed to delivery; (2) Developing a custom, in-house physical access control solution that includes modern capabilities, such as digital IDs. This option was not selected as the Company lacks the expertise to build such a solution. Custom-developed solutions have higher long-term, and generally result in significant waste, as well as lower speed to delivery; and (3) Implementing a new physical access control system that includes modern capabilities, such as digital IDs, that reduces waste and cost and improves speed to delivery. There are vendors in the market that specialize in physical access control systems that offer proven capabilities the Company is looking to implement. This option was selected as it will allow the Company to meet its objectives of lower waste, lower cost, improved speed to delivery, by implementing digital IDs and enabling tighter integration between the physical access control system and the Company's other security platforms.

- The **Saviynt Enterprise Identity Governance and Access ("EIGA") Implementation** project requires $347,456 in capital and $46,637 in O&M in the test year.

  - **Description:** The project will implement Saviynt EIGA module, consolidate Identity Access Management ("IAM") functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications.

  - **Problem Statement:** The current version of AccessNow reached end-of-life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and customizations. While beneficial for end users, these integrations increase the risk of system failures, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduces failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention.

- **Objectives:** This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt EIGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) Minimizing custom code and focusing on configurations only by utilizing out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface.

- **Scope:** This project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Standardizing processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access system; (4) Addressing issues with aging applications, multiple IAM platforms, integration challenges, and antiquated HR processing.

- **Alternatives:** Alternatives considered include: (1) Implementing hot fixes to AccessNow version 8.1.5 to ensure support through mid-2023; (2) Upgrading only the application to current supported version, excluding the new web portal but will include new application functionality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break / fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating AccessNow software.

- The **Security Threat Intelligence Tool** project requires $190,774 in capital ($152,619 ROM Adjusted Capital) and $31,781 in O&M in the test year.

- **Description:** This project will implement a threat intelligence application that will actively assess physical and cyber threats in the environment, visually display historical and active threat data for situational awareness and provide alerts to employees based on location of the threat. This information will allow the Company's combined physical and cyber security operations center (Fusion Center) to alert employees who are in the proximity of a physical threat on the risks they may face, help inform decisions on hardening facility locations and alert employees of active cyber threats that are currently impacting other companies. The ability to proactively alert employees of the threats will have a positive impact on Safety and Cyber Security for the Company by reducing response time to incidents and reduce the likelihood an employee will be physically injured.

- **Problem Statement:** The Company's Fusion Center and Physical Security teams currently do not have the ability to actively collect or disseminate threat intelligence in real time. This gap in technology increases the risk of physical and cyber-crime to employees and Company assets. As the threat landscape changes, automating data collection is essential to detecting and determining threats in real time. Currently the Company's Fusion Center manually searches through sources to collect threat intelligence. The data that is manually collected is often out of date by up to one week. This re-active approach has led to gaps in information and the inability to accurately depict the threat environment. Relying on manual processes and stale data can result in employees to be put in threatening situations. Cyber threats change daily in the environment. Spending valuable time to search manually through threat information causes delays in protecting the Company's sensitive data including electric and gas critical infrastructure, financial, and customer data.

- **Objectives:** This project creates value for the Company by: (1) Implementing a threat intelligence tool that actively assesses threats in the environment; (2) Visually displaying historical and active threat data for situational awareness; and (3) Providing alerts to co-workers based on their location. Accurate and timely information about threat actors and their tactics enables the team to proactively perform targeted investigation, containment, and remediation.

- **Scope:** The project scope includes: (1) Implementing a single threat intelligence application that will provide intel on both physical and cyber threats; (2) Integrating with the current security orchestration platform; and (3) Building automation to notify co-workers of physical threats that are identified through intel provided in the application.

- **Alternatives:** Alternatives considered include: (1) Maintaining the Company's current security posture of manually gathering information on threats through social media, law enforcement, and news reports. Continue to alert employees of active threats once they are noticed by Fusion Center employees. This alternative was not selected because the process to gather the data is completely manual and the data gathered can be outdated by up to a week. Stale data can put Company assets and employees in dangerous situations. Using outdated information delays response time for Company crews and law enforcement to address the situation. (2) Expanding the Company's current mass notification tool use to integrate security threat intelligence intel. This alternative was not selected due to the risk of delayed response time to receive threat notification from the current vendor in comparison to other vendors in the market. (3) Building an in-house threat intelligence application to fulfill the security threat intel requirements. This alternative was not selected because developing security platforms of this type is not in the core competences of the Company. The Company's resources do not have access to the wide range of threat data that other companies leverage to develop a threat intelligence application. In addition, the cost to maintain an in-house application of this type would not be economically practical. (4) Implementing a threat intelligence application that meets the Company's security threat intelligence requirements. This alternative was selected.

- The **Security/OT Field Modernization** project requires $129,249 in capital ($103,399 ROM Adjusted Capital) and $46,236 in O&M in the test year.
  - **Description:** This project will implement new infrastructure for accomplishing improved security in the field for OT assets.
  - **Problem Statement:** Gas and Electric technicians are using corporate laptops, to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. Vendors and contractors have access to the Company's critical infrastructure using non-Company laptops. Best practice is to use dedicated laptops to connect to critical infrastructure.
  - **Objectives:** The value of this project is deploying dedicated Company OT laptops and associated OT infrastructure that can move between OT locations only and providing a secure environment.
  - **Scope:** This project will procure and configure approximately 130 devices that will be used to manage critical OT infrastructure.
  - **Alternatives:** The Company reviewed several options to mitigate cyber security risks inherent with the use of standard corporate laptops managing critical infrastructure. The alternatives considered are: (1) Continue utilizing existing workflow of using Corporate domain laptops with software installed; (2) Bring in an outside vendor to design and implement a proposed infrastructure; (3) Complete disallowance of all local access to critical systems; (4) Extending the OT network to remote Company locations; (5) Deploy a dedicated Company OT laptop and OT

communications circuits, which includes cellular connectivity. The dedicated OT laptop and communications circuits presented the best way to secure the critical infrastructure by limiting internet and e-mail access. Vendors and contractors could also utilize these approved dedicated systems for managing infrastructure they help support at Company locations. Based on the analysis performed, the Company chose to deploy a dedicated OT laptop and communications circuits.

- The **TSA Critical Facility Structure** project requires $392,000 in capital and $14,267 in O&M in the test year.

  - **Description:** This project will implement enhanced security measures outlined by the Transportation Security Administration (“TSA”) for critical facility assets in order to bring the locations up to enhanced status and avoid non-compliances. This project will increase the security and reliability of gas delivery to customers while also meeting federal requirements.

  - **Problem Statement:** Pipeline facilities that are deemed critical are required to apply enhanced security measures. Today, the Company currently has designated four locations as critical. However, based on the April 2021 update to the TSA Pipeline Security Guidelines, Section 5 (Critical Facility Criteria), a significant number of the Company’s gas infrastructure that were not previously subject to evaluation will now fall into scope.

    As the Company continues to analyze the remainder of our gas assets, there is the potential for an additional 1,000 pipeline facilities (pipeline interconnections, metering and/or regulating stations, pump stations, compressor stations, operational control facilities, main line valve, tank farms and terminals, etc.) that may be deemed critical. The Company will be taking a phased implementation approach and will begin the process by implementing the enhanced security measures at the remainder of our compressor stations. Failure to update our sites will put the Company out of compliance with the updated guidelines.

  - **Objectives:** This project provides value to the Company by: (1) Implementing enhanced security measures outlined by the TSA for four critical assets; and (2) Increasing the security and reliability of gas delivery to customers while meeting federal requirements.

  - **Scope:** This project will implement the following enhanced security measures: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fencing and barriers; (6) gates; (7) locks and key control; (8) fence intrusion; (9) subcontractor work of trenching poles, etc.; (10) facility lighting; (11) background investigations for personnel working at the site; (12) security equipment maintenance and testing; (13) security vulnerability assessments; (14) security communication plans;

(15) personnel training; and (16) security drills and exercises for the identified locations.

- **Alternatives:** Alternatives considered were: (1) To not implement the enhanced security measures outlined by the TSA for critical facility assets. This option was not chosen due to the risk of not complying with the TSA enhanced security measures. (2) To implement the enhanced security measures outlined by the TSA for critical facility assets. This alternative was chosen to avoid the risk of not complying with the TSA enhanced security measures, such as increased vulnerability of attacks, financial penalties, and operational disruptions.

Q. Are the expenses and expenditures identified in this testimony reasonable and prudent?

A. Yes. The O&M expenses and capital expenditures requested in this case will help the Company achieve the outcomes of the NGDP, continually improve the experience of customers' interactions with the Company, and maintain a reliable and secure technology base that is exposed to ever-increasing and serious cyber security threats over time. Technology is the backbone of Company operations and two-way customer communications. The Company has demonstrated the prudency of project expenditures and operational O&M requirements.

This testimony has provided detailed synopses of each project, a supplementary exhibit of the total project cost, hard savings, and cost/benefit analysis for each project in the test year, and a deep dive into benefits for several high priority projects. These are responses to concerns from previous rate cases and to provide additional insight to support recovery. The Company is seeking full recovery for these investments and operational expenses for technology solutions that keep its systems available, customers safe from growing cyber security threats, and that deliver on an improved gas future in the Company's NGDP.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

DIRECT TESTIMONY

OF

COREY E. BALLINGER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Corey E. Ballinger, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Fleet Acquisition & Asset Disposition Manager.

Q. What is your formal educational experience?

A. I have a High School Diploma and attended Jackson College in Jackson, Michigan.

Q. What are your responsibilities as Fleet Acquisition & Asset Disposition Manager?

A. I provide oversight to Fleet Acquisition supporting the Company's current and long-term capital replacement strategy, vehicle disposition, licensing, rentals, and internal electric vehicle ("EV") strategy. In addition, I provide oversight to the Company's Investment Recovery Center ("IRC") function, which handles the disposition of surplus Company assets.

Q. Would you please describe your previous work experience?

A. In 1999, I started my career at American Tooling Center in Grass Lake, Michigan as a Tool and Die Apprentice. American Tooling Center designs and builds large line dies for all major manufacturers in the automotive industry. In 2001, I was hired by Consumers Energy as an Operations Assistant in the Company's mailroom. In 2002, I accepted an Administrative Assistant position in Fleet Acquisition. In this role, I assisted with writing fleet specifications and managed the internal rental and licensing programs. In 2005, I was promoted to Fleet Field Leader in the Southern Zone. The Fleet Field Leader position consisted of oversight of all preventative maintenance and repairs to Consumers Energy's

Fleet within the zone. My role as a Fleet Field Leader continued to expand across multiple zones until I had oversight of 14 locations, 2 schedulers, and 23 mechanics. In 2013, I accepted the position of Sr. Technical Analyst II in Fleet Acquisition. In this role, I was responsible for the design and purchase of Consumers Energy vehicles, trailers, and equipment. I created Requests for Proposals and provided oversight for the annual Fleet Purchase Plan for Gas Operations. In 2022, I was promoted to Fleet Acquisition and Asset Disposition Manager.

Q. Have you previously been a witness, or supported witnesses, in any proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I was the witness for the most recent Electric Rate Case No. U-21585 and I provided support to the fleet witness in Electric Rate Case Nos. U-21224 and U-21389, as well as the two most recent natural gas rate cases, Case Nos. U-21308 and U-21490.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's costs related to the gas business portion of Fleet services. To that end, I will:

I. Describe the Company's Fleet and how it is managed through Fleet Services;

II. Explain the Company's Fleet Replacement Planning Process;

III. Explain the Company's Fleet Electrification Strategy; and

IV. Sponsor the Company's Fleet capital spending projections.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (CEB-1)	Schedule B-5.2	Summary of Actual & Projected Capital Expenditures Fleet Services;
Exhibit A-27 (CEB-2)		Fleet Responsibility Costs;

Exhibit A-28 (CEB-3)	Detailed List of Projected Gas Capital Expenditures Fleet Services for the Years 2023, 2024, 2025 and test year 12 months ending October 31, 2026; and
Exhibit A-29 (CEB-4)	Summary of Fleet Tooling Actual & Projected Capital Expenditures.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. Please briefly describe the exhibits that you are sponsoring.

A. I am sponsoring Exhibit A-12 (CEB-1), Schedule B-5.2, which is a Summary of Actual and Projected Capital Expenditures for Fleet Services for the calendar year 2023, bridge period (22 months ending October 31, 2025), and the projected test year 12 months ending October 31, 2026; Exhibit A-27 (CEB-2), which provides details of the Company's fleet responsibility dollars; Exhibit A-28 (CEB-3), which provides details of the Company's Fleet acquisitions in the historical year 2023, bridge period (22 months ending October 31, 2025), and the projected test year 12 months ending October 31, 2026; and Exhibit A-29 (CEB-4) which is a Summary of Actual and Projected Fleet Tool Capital Expenditures for the historical year 2023, bridge period (22 months ending October 31, 2025), and the projected test year 12 months ending October 31, 2026.

I. <u>FLEET SERVICES FUNCTION AND RESPONSIBILITIES</u>

Q. What functions compose the Fleet Services organization?

A. The Fleet Services organization consists of three departments which collaboratively work together to provide value to Gas Operations in serving customers. The three departments include Fleet Maintenance Operations, Fleet Acquisition, and Shared Services Governance Performance and Technology.

Q. Are you addressing all support organizations related to Gas Operations Support in your direct testimony and exhibits?

A. No. I will be addressing Fleet Services only. Facilities will be addressed in the direct testimony of Company witness Quentin A. Guinn.

Q. Please explain the responsibilities of Fleet Maintenance Operations.

A. Fleet Maintenance Operations is responsible for maintaining a safe, cost effective, and reliable fleet. This is accomplished through preventative maintenance, regulatory inspections, parts inventory management, and maintenance scheduling across 36 garage locations with approximately 110 mechanics. Maintenance Operations also oversees mechanic contractor crews for preventative maintenance and repairs performed in the field.

Q. Please explain the responsibilities of Fleet Acquisition.

A. Fleet Acquisition executes all functions related to the acquisition and disposition of Company-owned and rented vehicles and related equipment. This includes management of the Fleet capital purchase plan, vehicle specification design, licensing/title, registration, and asset retirement.

Q. Please explain the responsibilities of Shared Services Governance Performance and Technology department.

A. Governance Performance and Technology provides fleet with support of data integrity, Telematics data management, departmental metric visual management, process automation, oversight of waste elimination initiatives, and evaluates benchmarking and data analysis provided to the Company. This team is also responsible for meeting all regulatory and compliance requirements with the American National Standards Institute, Department of Transportation, Michigan Motor Vehicle Code, and Federal Motor Carrier

Safety Administration. Additional responsibilities include Fleet Operations Policies and Procedures, regulatory and technical support, and tooling for fleet mechanics and the Company's EV strategy. The department also provides oversight for quality inspection audits and safety requirements related to regulatory compliance.

Q. Please explain the Company's overall fleet structure.

A. The Company's fleet includes approximately 7,207 owned, leased, and rented units across 36 locations. These units include light duty vehicles (approximately 2,800 units), medium and heavy-duty trucks (approximately 1,500 units), various types of equipment (approximately 1,400 units), and trailers (approximately 1,900 units). Internally, the Company categorizes its fleet into several specifications ("spec(s)"), each of which is a given type, model, and description of a vehicle. Each spec has a defined intended use, acquisition cost, operating cost, and expected life in years and mileage.

Q. How is the Company's fleet divided between the electric and natural gas businesses?

A. The Company divides its fleet between the electric and natural gas businesses by determining which business unit at a given location is using each particular vehicle. The needs of the business require the deployment of dedicated teams to safely complete work utilizing specific tools and processes – this extends to the vehicle supporting said work. These vehicles are ordered and upfitted to support specific work and are, therefore, specialized for the work they perform; however, the Company does seek ways that units can be shared across the business when possible. The fleet requirements for the location will vary based on the service provided to the customer (electric, gas, or both), crew counts, and region. Additionally, some Company fleet units serve both electric and gas functions and are referred to as "common" units, which are utilized by support organizations, such as Facilities, Fleet, and Supply Chain. Overall, the Company's fleet is 40% electric, 50% gas, and 10% common by number of vehicles.

Q. What is the purpose of Fleet Services as it relates to the Company's gas business?

A. Specific to the Company's gas business, Fleet Services' purpose is to provide vehicles and equipment that enable Gas Operations to serve customers with safe, reliable, and affordable gas service. This is accomplished by ensuring that the Company's Fleet assets are available to execute the work plan and respond to emergencies in the most efficient, cost-effective, and safe manner when required.

Q. Does the Company's fleet incur both capital and operating and maintenance ("O&M") costs?

A. The Company makes direct capital investments into its fleet as provided in Exhibit A-12 (CEB-1), Schedule B-5.2, and Exhibit A-27 (CEB-2). The Company also incurs other costs related to its fleet that are treated as "fleet responsibility" dollars, which in this case are presented in Exhibit A-27 (CEB-2).

Q. What are fleet responsibility dollars?

A. In addition to direct capital expenditures for fleet vehicles, tools, and other equipment, the Company also incurs other costs related to its fleet that are treated as "fleet responsibility" dollars. The Company does not have specific Fleet O&M expenses.

Fleet operating costs are reported in responsibility dollars. Each fleet unit has defined work assignments that determine which functional areas are allocated the associated responsibility dollars for the unit. Fleet responsibility costs are allocated to both capital and O&M expenses based on the work assignment performed.

Q. Please explain how fleet responsibility dollars are allocated to both capital and O&M.

A. The process for allocating fleet responsibility dollars is a multi-step process. The first step in the process is that costs associated with each fleet vehicle or piece of equipment are charged to an internal order. Each fleet vehicle/equipment has its own internal order that collects costs like fuel and maintenance, which is assigned to a department/responsibility area.

The next step is that the costs from the internal orders are moved to separate fleet clearing accounts for each department/responsibility area. The final step in the process is the allocation of the costs from the fleet clearing accounts. The costs in each clearing account are allocated to work orders or cost centers based on the labor charges for that department/responsibility area. Additionally, the fleet costs to be allocated are separated between labor and non-labor fleet loading.

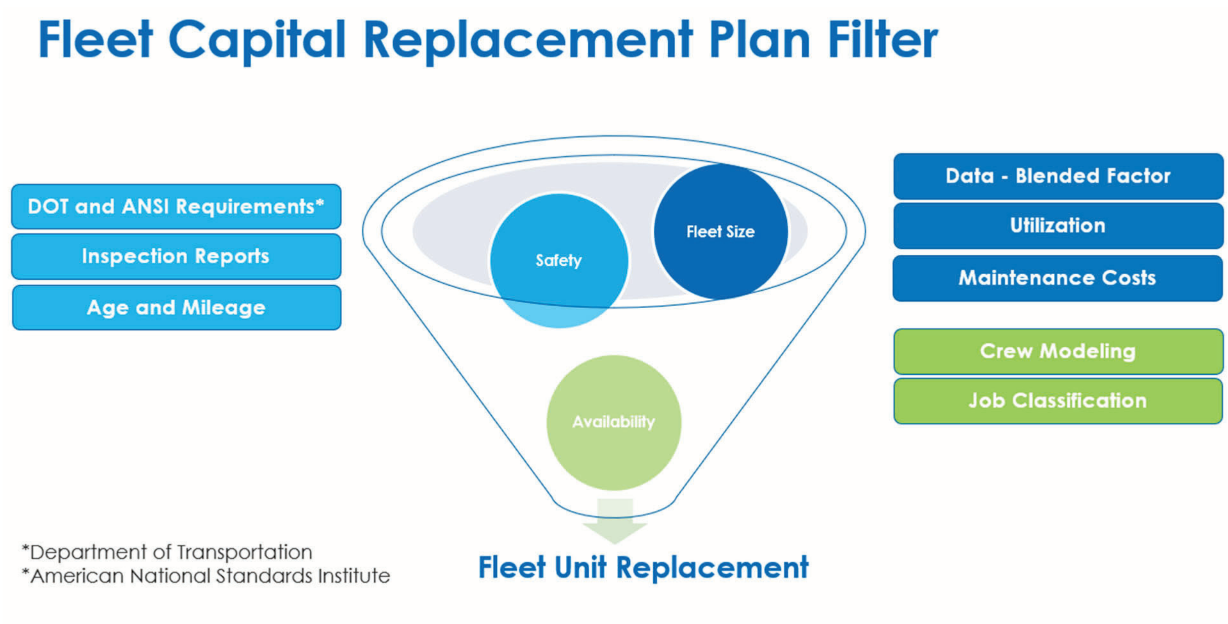
II. FLEET REPLACEMENT PLANNING PROCESS

Q. What is the Company's overall Fleet Replacement Planning Process as it is being presented in this case?

A. As previously presented in Electric Rate Case Nos. U-20963, U-21224, U-21389, and U-21585, and Gas Rate Case Nos. U-21148, U-21308, and U-21490, the Company develops its Fleet Vehicle Capital Replacement Plan using the Fleet Replacement Planning Process, which is a process that incorporates three phases. In the first phase, the Company identifies vehicles that are at or near the end of their expected life and are eligible for replacement, using a tool called the Blended Factor that is described in more detail below. Next, in the second phase, the list of vehicles identified by Blended Factor Analysis for potential replacement is further developed by certain data tools, described below, particularly by fleet cost data, followed by crewing data, and, lastly, fleet utilization data. In this second phase, the Company's fleet leadership also works with Operations leadership and personnel in the field, which includes operators and mechanics, to identify which specific units should be replaced, incorporating qualitative inputs like maintenance reports and local area work needs. This second phase allows for further evaluation of the vehicles identified in the first phase to better determine which vehicles should be replaced. Thereafter, in the third phase, the list of vehicles identified for retirement is finalized based on the evaluations performed in the first two phases, and the ordering process begins. If an existing contract is already in place, orders are placed immediately with the manufacturer or vendor. For vehicles not covered by an existing contract, detailed specifications are written and requests for proposals are sent out to vendors (including minority-owned and Michigan-based businesses whenever possible). Once bids are received, they are evaluated and awarded based on cost, product support, and quality.

Q. Please further explain how the Company establishes its Fleet Replacement Planning Process.

A. The Company strives to replace assets at the optimal moment in the vehicle's service life by incorporating several factors in the decision-making process, particularly within phases 1 and 2. In doing so, the Company uses data gathered for each spec that is documented, monitored, and corroborated with detailed in-person inspections. Data is generated by the fleet through Telematics, including utilization rates, fleet age, and detailed inspections as a basis for determining future fleet purchases of specific capability and utility. The Company's process for compiling and analyzing qualitative and quantitative inputs to develop its Fleet Vehicle Capital Replacement Plan is illustrated by the "filter" shown below.



Q. Please explain how the Fleet Capital Replacement Plan Filter works.

A. When the Company goes through its Fleet Replacement Planning Process, specifically within phases 1 and 2, certain data – such as the Blended Factor, utilization, operating cost, and crewing needs – is analyzed to determine if a given vehicle needs to be replaced. During the Fleet Replacement Planning Process, other qualitative inputs like vehicle inspection reports and the assessments of field employees provide further insight on replacement needs. The result of this process, specifically following the first and second phase, is a list of fleet units to be replaced.

Q. Can you describe, in further detail, the Blended Factor used in phase 1 and the Fleet Cost Tool, Crewing Model Tool, and Fleet Utilization Tool used in phase 2?

A. Yes. These are each described in the following sections.

A. Blended Factor

Q. Please further explain the Blended Factor.

A. The first step in the Company's process for establishing its Fleet Vehicle Capital Replacement Plan is informed by the Blended Factor. As previously mentioned, the Blended Factor takes age, usage, and mileage into consideration and establishes a replacement priority for units that are more economical to replace than continuing to maintain. The Blended Factor for any vehicle is calculated as shown in the illustrative example below:

Blended Factor Calculation

$$\textbf{Blended Factor Rating} = \left(\frac{[\text{Age Factor} + \text{Usage Factor}]}{2}\right)$$

$$\textbf{Age Factor} = \left(\frac{\text{Actual Age in Months}}{\text{Expected Life in Months}}\right) - 1$$

$$\text{Example: } \left(\frac{102}{84}\right) - 1 = .21$$

$$\textbf{Usage Factor} = \left(\frac{\text{Estimated Mileage}}{\text{Expected Life Mileage}}\right) - 1$$

$$\text{Example: } \left(\frac{223{,}180}{150{,}000}\right) - 1 = .488$$

$$\textbf{Blended Factor Example: } \left(\frac{[.21 + .488]}{2}\right) = .349$$

Equipment and engine operation hour calculation: 1 hour = 25 miles

For equipment that does not have mileage (no odometer), the Blended Factor calculates usage from the engine hours. For medium and heavy-duty vehicles, the Blended Factor calculation also uses total engine hours, assuming that one hour of engine operation is equivalent to 25 miles of travel. Using this calculation, a Blended Factor result greater than 0.00% indicates that a vehicle is at or past its expected life and is therefore eligible for consideration for replacement. This indicator does not mean that a vehicle with a result greater than 0.00% is automatically selected for replacement; it is instead a *starting point* each year for the Company to use as a foundation in the selection of vehicles for replacement.

Q. Why is it important for the Company to consider the expected life in months and expected life in mileage for each of the respective specs?

A. The Blended Factor formula incorporates two key indicators of end of its expected life: (1) how old a vehicle is and (2) either how many miles it has traveled or total hours of operation. Expected Life in Months considers manufacturer inputs, reliability, operating conditions, and operating cost to determine the duration the Company expects a vehicle to operate safely and cost effectively. Expected life in mileage or hours is also based on similar considerations as an indicator of wear and tear. The Company makes these evaluations to set a foundational benchmark to assess potentially replaceable vehicles. The fleet has a diverse range of specs for specific operational needs, and not all specs have the same expected life. Even within the same spec, individual units can vary in condition depending on utilization and wear. Managing each spec to its appropriate expected life ensures that the Company always has the right type of vehicle available to serve the needs of customers in the safest, most reliable, and most efficient manner possible, while minimizing costs.

Q. Why is the use of the Blended Factor appropriate?

A. The Blended Factor is an internal data-based algorithm that incorporates unit age, utilization (in mileage or hours), and expected life, allowing the Company to prioritize, plan, and target specific vehicle(s) for replacement. As a key feature of the *first phase* of the replacement process, the vehicles denoted by the Blended Factor to be approaching the end of their expected life provide the basis for planning phases ahead. This process is critical to assure that the Company can order a timely unit replacement, especially given the supply chain challenges that have emerged in the last three years. While there has been some improvement in the expected delivery dates for some products, planning around potential delivery delays and availability is still a concern as demand for new medium and heavy-duty equipment remains high. By using the Blended Factor, the Company can strategize future spending for replacement units for specific years by consulting with suppliers on current and future availability, thereby preparing the Company to order units given current lead times to receive a unit once an order is placed.

Q. What conclusions do you draw regarding the Blended Factor?

A. The Blended Factor provides an objective standard that uses clear internal fleet data to identify units for potential replacement and adds a level of predictability regarding which units will need to be replaced to improve the cost-effectiveness of the replacement process. Based on the above Blended Factor calculations, it is indicated that out of 7,207 units currently in the fleet, there are approximately 2,794 units greater than 0.00%.

B. <u>Fleet Cost Tool</u>

Q. Please explain the Company's fleet cost tool.

A. As part of the second phase in its Fleet Replacement Planning Process, the Company is utilizing the fleet cost tool, incorporating data analytical tools to support near- and long-term cost-effective vehicle purchase plans. These analytical tools include tracking vehicles by spec and the average age of each spec, fleet O&M costs, and geographical location. Additionally, the fleet cost tool provides at-a-glance total and average per-vehicle operating costs for each spec from various perspectives, including operating costs per mile, by age, and by specific vehicle. These tools provide data indicating vehicle count and average age, broken out by spec. The purpose of these tools is to provide overall cost status summaries of the fleet, as well as a platform to perform more detailed cost analyses of individual vehicles. The following are descriptions of several tools the Company has developed.

Q. What are these tools that the Company has developed to support fleet cost analyses?

A. For an overall summarization of fleet age and operating costs, the Company has developed "Unit Age and Operating Cost" and "Unit Count and Average Age" tools to provide information regarding fleet operating costs correlated with age. Operating costs include maintenance, fuel, and repairs. This information can be filtered by vehicle year and spec and can assist in identifying trends that will enable cost forecasting to support future purchasing decisions.

Q. What are additional analytical tools related to fleet cost?

A. The Spec Detail Information Analysis identifies equipment count by spec and is designed to highlight yearly fleet growth by spec, which helps identify trends and how the fleet's makeup and size changes over time.

Q. Are there any other analytical tools that are part of the fleet cost tool?

A. The Age and Cost Spec Detail Analysis is designed to provide detailed cost information for a specific unit, including total operating cost, as well as average costs over time for specific specs. In this analysis, the Company evaluates equipment count, total operating cost, average unit operating cost, median unit operating cost, and average unit age. Finally, a Location Summary Analysis displays a particular territory, city, spec, equipment count, and total operating cost for vehicles distributed throughout the Company's service area.

Equipment Count by location is displayed on a map with circle size indicating high/low equipment counts and color indicating zone. Average Unit Age and Total Operating Costs are summarized in cards at the top of the page. This page allows the user to filter on Year, Usage Indicator, Rental Status, and Spec. The purpose of this tool is to allow the user to use the filters to summarize equipment count, cost, and age by location.

Q. Why are these fleet cost analytical tools appropriate for the Company to use?

A. Using the Company's own data, the information these tools provide is used to help the Company plan the cost-efficient replacement and acquisition of new vehicles. The Fleet Cost Tool data provides information from several perspectives that helps narrow the pool of vehicles identified by the Blended Factor for replacement. For example, the Blended Factor may identify many units within any given spec that are at or near the end of their expected life, but a further examination using this tool can help inform how the unit is performing in relation to other identical spec vehicles in the fleet from a cost perspective. If the unit has become uneconomical to operate compared to other vehicles in the same spec, it may be best to replace that vehicle for a more cost-effective solution sooner rather than later. Conversely, a vehicle that has reached the Blended Factor end of expected life may still have years of economical service possible based on operating cost reported by these tools. This fleet cost tool also allows the Company's fleet management to understand how fleet costs have changed year-over-year, including the ability to examine costs of specific units to help inform if they are good candidates for replacement. The tool is intended to provide an overview of past fleet metrics, and helps to identify relationships between unit age, mileage, and operating costs. It also shows fleet age by spec which can be helpful when multiple units of the same spec were purchased in the same year. This is important information to consider when prioritizing the most appropriate vehicles to replace at any given point for the benefit of customers.

Q. What has the Company learned to date from using its fleet cost tool?

A. The fleet cost tool has allowed the Company to make informed decisions while reviewing units identified for replacement. This tool provides the Company with an at-a-glance total of overall costs of a particular unit. As the fleet team strategizes how and where to replace vehicles, the cost tool assists in framing how to best benefit the customer in the decision-making process.

As noted, the Blended Factor calculation is a starting point in the decision-making process, with the expectation that the list can be modified as further analysis proceeds. The cost tool facilitates a review of repairs and improvement costs associated for each vehicle that can extend its service life. For example, feedback sought and received from field leaders on the overall condition and serviceability of a truck can show that it should be kept in service instead of being replaced. This includes investments like engine or transmission rebuilds, or body rust repairs. The fleet cost tool quickly identifies which units require closer scrutiny when making purchasing decisions. This benefits the customer in that the Company gets as much service life out of units as is economically prudent.

C. <u>Crewing Model Tool</u>

Q. Please explain the Company's crewing model and crewing model tool.

A. As part of the second phase of its Fleet Replacement Planning Process, the Company's crewing model is used to calculate how many vehicles are needed based on the size of the workforce. This model incorporates all gas department vehicles and details about which employees are assigned to operate these vehicles. The gas departments include Gas

Service, Gas Transmission, Gas Compression, Gas Construction, and Gas Distribution. These departments operate the following types of vehicles: dump trucks, digger derricks, vans, pickup trucks, and other support vehicles. The crewing model tool illustrates how many vehicles are needed and how many vehicles are available, giving visibility to gaps.

Q. What information does the tool show?

A. The tool lists Company locations and, for each location, shows the number of units at that location by workgroup, breaking down the number of employees and the number of different types of units located there. Based on this information, the tool provides the gap between the actual number of vehicles at the location and the number of vehicles needed.

Q. How was this crewing model developed?

A. The Company's Gas Operations Department's workforce size and crewing influences the number and types of vehicles needed to serve customers. Crewing is determined by the work required and influenced by safety and policy procedures related to the work performed. In the crewing model, the Company uses standard crewing of the following truck-to-employee ratios:

- Gas crewing consists of one Gas Line Worker ("GLW") and/or one Trenching Machine Operator ("TMO") to make one crew. Each crew is assigned a Gas Service Truck (spec 44) and a support vehicle. The support vehicle could be a dump truck or a pickup. The crewing model calculates vehicle needs according to the following ratios:

Vehicle Type	Model Ratio
Gas Service Truck (spec 44)	1:1 TMO to Gas Service Truck
Digging Equipment	1:1 GLW/TMO to Digging Equipment
Pickup	1:1 GLW to Support Vehicle
Fillet Welder (Spec 28)	1:1 GLW to Fillet Welder

- Employees in Gas Meter Operations, Customer and Field Services, usually operate as single workers, rather than in a crew, meaning they have a 1:1 vehicle ratio.

Q. Why is this crewing model appropriate for the Company to use?

A. The crewing model is based on industry best practices and Occupational Safety and Health Administration ("OSHA") requirements.[1] To provide a safe, reliable, and cost-effective fleet, it is important that the Company's fleet be adequate in size to complete the established work plan, work safely, and adhere to OSHA requirements.

Q. What conclusions can you draw from the data shown in the crewing model tool?

A. The model shows that the quantity of production units (gas service trucks, support vehicles, welders, and digging equipment) currently in the Company's fleet will continue to be evaluated based on established work plans and employees needed to perform the work (more information on how utilization data is calculated is provided in the next section of this testimony). The model can help identify surplus or deficiency of assets in each specific area and units that are down for repairs or regular maintenance. This visibility allows the Company to reallocate surplus assets to areas with deficiencies to ensure each area is adequately supplied based on the model. Backup vehicles must be ready to meet the needs of the crews as daily schedules develop, meaning that some additional vehicles may be needed on short notice. The Crewing Model allows for backup vehicle availability for such circumstances to reduce the risk of gaps between crews and vehicles needed in the field.

The crewing model assumes the Company will onboard new workers or add replacement workers consistently and in a timely manner as work plans develop to drive the need for workers and as attrition rates affect the workforce. However, the Company

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[1] 1926.960 - Working on or near exposed energized parts. | Occupational Safety and Health Administration (osha.gov): https://www.osha.gov/laws-regs/regulations/standardnumber/1926/1926.960

does not always receive new vehicles at the same time new workers are onboarded. For this reason, it is possible that new vehicles will be received and paid for before workers are ready to use them, but those vehicles *will* be put into use once the planned hiring is complete. Utilization rates for vehicles may at times reflect this reality.

Q. What has the Company learned to date from using its Crewing Model?

A. The Crewing Model offers the ability to find gaps in available units, and much like a checklist, allows the Company to proactively prepare for any emerging vehicle needs based on how new projects and employees are planned or deployed. In this manner, the Crewing Model complements the other fleet tools the Company is developing by ensuring that units are allocated as effectively as possible before and after any new units are purchased. The customer benefits from this because the Company is constantly working to keep its fleet right sized, with as little redundancies as possible.

D. Fleet Utilization Tool

Q. Please explain how the Company captures utilization data for its fleet.

A. All vehicles use a Telematics device that is directly wired to that asset's onboard computer or switching. Each installed Telematic device communicates, via cellular signal in real time, information about the asset status including the unit's exact Global Positioning System ("GPS") location, date, time, mileage driven, and hours in operation. A vehicle is considered in use for any given day when it has traveled five or more (5+) miles at any time or equipment that is in operation for 30 or more (30+) minutes per day. This captured data is then uploaded and compiled on a nightly basis into one tool that can then be used to run reports as needed to manage the operation. This data is compiled into a fleet utilization tool that can provide fleet use by zone, by vehicle type, or department and is used as part of the second phase in the Fleet Replacement Planning Process.

Q. How was this data process developed?

A. The electronic information captured by the Telematics system documents industry standard data points that are used to log key vehicle information. Since 1996, every vehicle manufactured in the United States has an On-Board Diagnostic ("OBD") port/interface that can easily be made accessible to Telematics systems and their associated electronic data gathering capabilities. The OBD system provides access to a vehicle's Electronic Control Unit, the main computer that controls vehicle engine, transmission, and other key vehicle functions. By connecting directly to the OBD of each vehicle, the Telematics system is able to collect the real-time information required to inform the Company to log the key data points required to document utilization.

Q. How is the Company's utilization data tied to the crewing model?

A. As explained in the crewing model section, vehicles are assigned in response to the requirements of the daily work plan and the employees needed to complete the work. Some types of vehicles, like bucket trucks, are used frequently for common field operations, whereas there are other types of vehicles that are highly specialized and designed for specific tasks that are not always required on a given day/night to serve customers but are no less crucial to properly service customers throughout the state. The Company's utilization data also accounts for the downtime that equipment must undergo when receiving inspections, maintenance and repair, or other ancillary equipment upgrades, and for the fact that some equipment must be available for on-call assignments and off-hour assignments.

Q. Why is this approach to utilization data appropriate for the Company to use?

A. By capturing real-time telematic data from each asset and compiling it in one dataset, the Company obtains the required raw data to detail the exact frequency, duration, and overall use of each asset, and this data is then searchable for reporting utilization rate purposes. Utilization data can illustrate where units may be underutilized. The customer benefits from this approach because the Company ensures that all vehicles and assets are tracked, monitored for maintenance and safety, and allows for the optimal cost-benefit relationship and return on investment for its fleet. This approach supports the analysis of what assets the Company needs to purchase to be sure that it is replacing vehicles at the end of their lifecycles, and to be sure that the Company is serving customers with safe, capable, and effective equipment.

Q. What conclusions do you draw from the Company's fleet utilization data?

A. The Company's utilization rate data informs us that a continual review of fleet equipment for under-utilized vehicles, what areas of the business they serve, and how that may impact the Company's ability to serve its customers, will be on an ongoing analysis. It is a key tool in determining why and where vehicles may be down (or showing lower utilization rates). For example, vehicles that are down for repair or waiting for parts are different from vehicles that are available but are not being used to serve customers when evaluating utilization rates. The Company analyzes its fleet utilization to determine if there are any redundancies that can be dispositioned in the future, such as through attrition and reallocating to raise utilization to more optimal levels.

E. <u>Benefits</u>

Q. Please summarize the Company's Fleet Replacement Planning Process.

A. The Company's fleet consists of 7,207 units of varying specs utilized for specific tasks to serve customers, divided between the electric and gas sides of the business. Assets referred to as "common units" are utilized by various other departments within the Company to support business operations. The Company employs a Fleet Replacement Planning Process (Replacement Filter, Blended Factor, Cost Data, Utilization Data and Crewing Models) to determine, in the most cost-effective and efficient manner, which units to replace. The Blended Factor identifies a pool of assets to consider replacing based on the mileage and age of each asset. Fleet cost data helps refine the initial group of eligible vehicles by helping to identify units that have become more costly than their value, or inefficient to maintain in the fleet. By applying crew modeling and utilization analysis, the Company checks to ensure that crew sizes support the potential number of vehicles replaced or added and confirms that replacement assets are appropriate based on usage rates. The customers benefit from this overall process because the systematic efforts noted above attempt to replace and/or add fleet assets at the most beneficial time possible. Each step in the process is designed to specifically identify which assets to add or replace, and the rationale and timing.

Q. What are the benefits of the Fleet Cost Tool for customers?

A. The tool helps the Company make decisions about which units should be replaced or kept by illustrating when the cost of maintaining the units outweighs the cost of a new unit, or investments made in units to keep them in service, which ultimately supports decisions made in the Company's Fleet Vehicle Capital Replacement Plan. The tool allows for visibility in significant investments such as a new engine or transmission in a vehicle that could extend its service life. The customer benefits from this analysis because the Company is using fleet dollars in the most economical way possible.

Q. What are the benefits of the Crewing Model for customers?

A. Having the ability to tie the workforce to the right vehicle by location enables the Company to have visibility to align assets with the workplan by department and location. As the Company strives to be a good steward of the fleet, the model helps validate if additional units are needed to meet the Company's workplan or, alternatively, if the Company has any surplus units that can be redeployed or retired. Absent this, the Company may end up lacking the appropriate vehicles to complete work for the customers' benefit.

Q. What benefits does fleet utilization data provide for customers?

A. Peak utilization of all vehicles is a balance between fully utilizing purchased assets and having the right asset in place and ready when needed at a moment's notice when responding to outages, new business, or construction situations. Fleet assets other than specialized equipment that are underutilized are not providing the maximum benefit to the customer. As good stewards of its fleet, the Company must provide the most cost-effective methods to assure that the fleet is a safe and effective part of the service it provides.

The Company's ability to serve its customers reliably, efficiently, and to a high standard requires an equally capable fleet. By methodically incorporating utilization processes that monitor fleet assets, the Company can maintain the fleet to manufacturers' specifications, as well as addressing the periodic wear and tear that comes with operating vehicles in often extreme conditions. Utilization data that monitors each type of vehicle can also assure that the Company is earning the best return on investment for the expected environment said vehicle is designed to operate in. For example, the Company expects that investing in a sedan should provide a life expectancy of seven years and approximately 150,000 miles under normal service. Utilization for a vehicle of this type may differ as compared to a utility truck sent as needed to address concerns in the field or support customers as the need arises. However, for both types of vehicles, regular monitoring of utilization reports will help the Company plan for the replacement of each vehicle with regular use over time. Additionally, analysis of any under-utilized vehicles will inform decisions on how many future investments in that type of vehicle are made going forward. Customers benefit when the Company is making best use of its fleet to deliver service. Utilization data helps the Company right-size its fleet by identifying where additional units are needed to accommodate the Company's workforce, if there are any surplus units, and if existing units can be more effectively used by the Company, such as by moving units to a new location or new department.

Q. Have there been right sizing efforts that benefit the customer?

A. Yes. Since mid-2022, the Company has reduced its total number of units by approximately 450 units utilizing the tools described above. These right sizing efforts benefit the customer by reducing overall cost through reductions and/or allowing a particular unit to be effectively utilized in support of serving customers.

Q. How does the Company's overall Fleet Vehicle Capital Replacement Plan benefit customers?

A. Overall, the Fleet Vehicle Capital Replacement Plan allows the Company to retire and replace vehicles in a cost-effective way by using qualitative and quantitative inputs to identify units for replacement, particularly by identifying those units with high maintenance costs and exhausted expected useful lifespans. Retiring and replacing those units in a systematic way is designed to keep maintenance costs down while ensuring that vehicles are available when needed to serve customers. The replacement planning process is a constantly self-evaluating cycle that relies on the data the fleet itself generates over time (mileage, age, and life cycle expectancy), inspections, maintenance and repair costs, and the local expertise to assist in prioritizing how the Company replaces units in the fleet. The customer benefits from this replacement planning process because the fleet is a crucial part of the overall service the Company provides. A replacement plan allows the Company to provide a safe, reliable, and cost-effective fleet to respond timely to utility outages, damaged utility service, utility service renewals, and new construction requests.

Q. Are there further benefits related to safety, quality, and the planet when determining the Fleet Vehicle Capital Replacement Plan?

A. Yes. By replacing vehicles in the fleet, newly introduced features from vehicle manufacturers are regularly incorporated into the Company's fleet, such as the following:

Safety-

- Backup sensors and rear-view cameras. This feature allows for safer backing, resulting in fewer rearward collisions, reducing vehicle and property damage, and increasing safety for the Company's customers and employees as well as collision avoidance and auto emergency braking, reducing collisions by advanced driver warning and applying brakes in advance of collision.
- Reduced stopping distance requirement from the Federal Motor Carrier vehicle safety standard for class 6-8 trucks. The standard distance required to stop a commercial vehicle was reduced, (National Highway Traffic Safety Administration 49 CFR Part 571, requiring a 30% reduction in stopping distance compared to currently required levels), which led to equipping trucks with larger braking systems to avoid collisions on buses and trucks manufactured on or after July 1, 2005.
- Light Emitting Diode ("LED") headlight technology. This allows a driver to see further down the road giving the driver more time to react to a situation.

LED headlights also save money due to less frequent bulb changes, thereby reducing time under repair.

Quality-

- Materials to manufacture vehicles are continuously advancing. For example, the Ford F-150 body is now stamped out of military grade aluminum, making the truck lighter, which increases fuel economy. Another added benefit of aluminum bodies is corrosion resistance, meaning less time and money spent repairing corrosion problems.
- Over the last 10 years, diesel engine exhaust gas recirculation coolers have improved, eliminating the need to replace them as frequently. This saves approximately $4,000 per replacement, where such replacements were occurring about every two years.

Planet–

- To align with National Highway Traffic Safety Administration's corporate average fuel economy standards, new vehicles are becoming more fuel efficient to align with their regulations. When replacing units within an appropriate lifecycle, the Company has an opportunity to purchase more fuel-efficient vehicles, including fully electric and plug-in hybrid vehicles where appropriate, ultimately reducing the Company's carbon footprint.
- Fossil fuel powered vehicles may be replaced with an EV if data supports electrification in that instance and could be a more fuel-efficient mode of transportation.

III. FLEET ELECTRIFICATION STRATEGY

Q. Does the Company plan to increase the number of EVs in its internal fleet?

A. Yes, the Company is planning to increase the number of EVs in its fleet to reduce fleet fuel, maintenance, and operating costs, as well as lowering carbon dioxide tailpipe emissions to reduce greenhouse gases. For purposes of this testimony, the Edison Electric Institute's definition of an EV includes all vehicles with a plug, including Battery EV, Plug-in Hybrids, and anti-idle job site work systems such as electric Power Take Off systems ("ePTO") units.

Q. How many EVs does the Company have in its internal fleet currently?

A. The Company's fleet currently operates 284 EVs, representing approximately 5% of powered units in the overall fleet.

Q. Does the Company have a target goal for electrification of its internal fleet?

A. Yes, as noted by the Michigan Council for Future Mobility and Electrification in its 2021 report, the decade ending in 2030 will be notable in that the growth of EVs in the state will present new opportunities for the Company and its customers.[2] This is consistent with the testimony of Company witness Jeffrey A. Myrom in the Company's most recent electric rate case, Case No. U-21585. Leading by example, the Company has, therefore, set a goal of electrifying 30% of its internal fleet by the year 2030, including light, medium, and heavy-duty vehicles (class 1 through class 6 and higher), equipment and powered trailers, as well as electrifying all class 1 and 2 (light duty) vehicles after 2030.

Q. How many vehicles does the Company plan to convert to electricity as a source of fuel by 2030?

A. The internal fleet currently consists of approximately 5,700 powered vehicles eligible for replacement by potential EVs. This includes sedans, pickup trucks, bucket trucks, forklifts, and others. Electrifying 30% of these units would result in the replacement of approximately 1,700 internal combustion engine ("ICE") units with fully or partially EV powered units by 2030.

Q. What types of vehicles does the Company expect to replace with EVs?

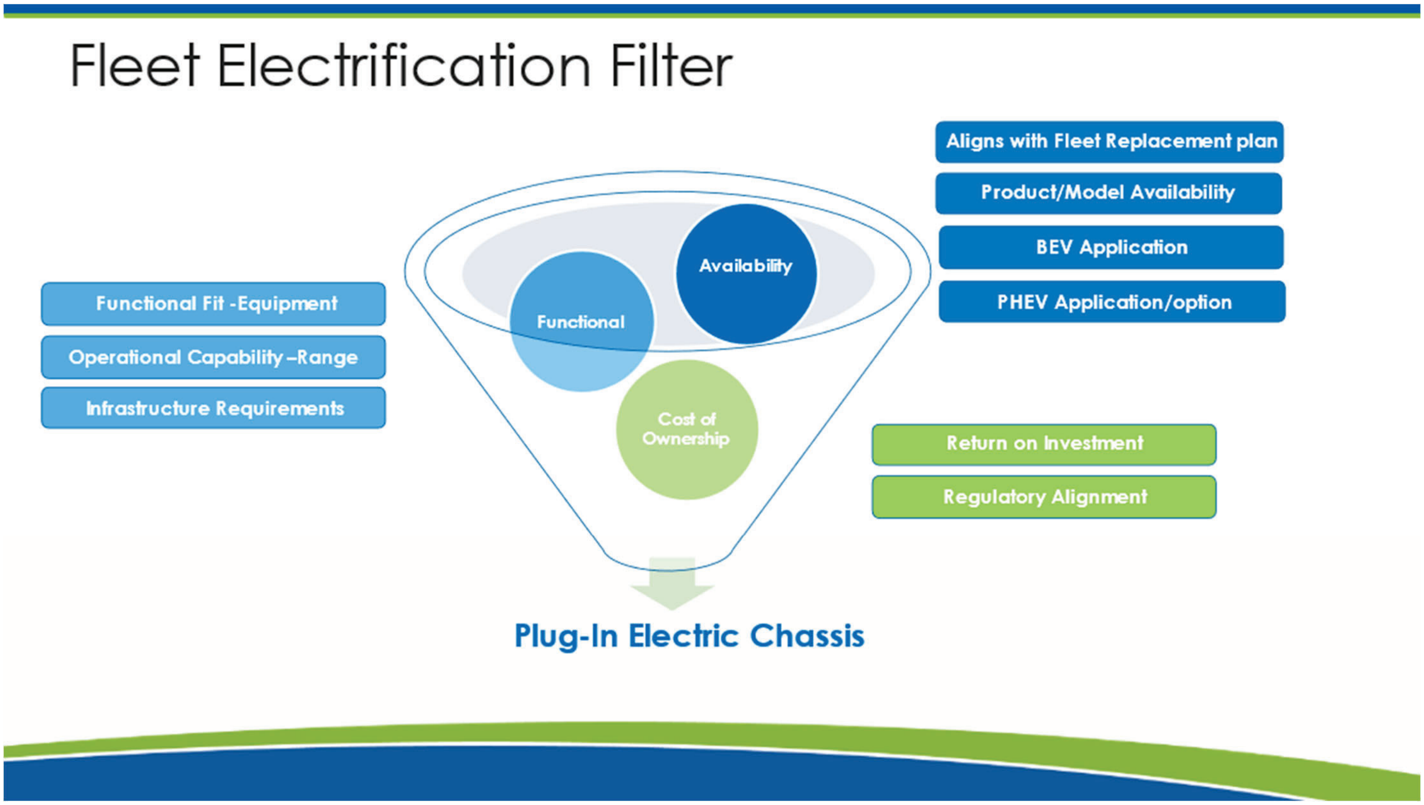
A. The Company expects that most of the initial ICE vehicles it will replace will be sedans and pickup trucks; however, as battery technology develops, there will be increasing

[2] cfme_report_2021_02.pdf (michigan.gov): https://www.michigan.gov/leo/-/media/Project/Websites/leo/Folder28/cfme_report_2021_02.pdf

availability for medium and heavy-duty vehicles to enter the market. For example, the Company has purchased one of the first available all electric bucket trucks in the world, which was delivered in the third quarter of 2024, as well as 20 all electric pickup trucks. The Company will deploy the electric bucket truck in its Grand Rapids location and has installed a DC Fast Charger there to support it.

Q. How will the Company determine opportunities to replace ICE vehicles with EVs?

A. The same replacement process, as discussed earlier in my testimony, will be used to determine opportunities to replace ICE vehicles with EVs, including the use of the Blended Factor, unit age, and overall condition analysis for each unit that has reached its end of life. Under this process, as a unit is targeted for replacement and reviewed according to the Replacement Plan, the unit is also considered for replacement with an EV. As the Electrification Filter shown below shows, consideration for electrification includes assessing a suitable replacement that is available in market, would have a functional role within the fleet, and lower cost of ownership. If the ICE under consideration for replacement meets the criteria required to pass through the filter, the unit is considered as an opportunity for replacement with an EV.



Q. Why is the Company concerned by functional fit and equipment considerations?

A. The Company partners with operational departments to understand how the potential replacement of an ICE vehicle with an EV will impact how teams complete their work. It is important to understand vehicle travel patterns, including mileage and driving duration, to assure that EVs are capable of supporting the work and have the travel range the Company needs to serve customers without compromise.

Q. Why is the Company considering range concerns with EVs?

A. As noted above, mileage range is a top consideration in determining how the Company integrates EVs into the fleet. It is critical to understand how current vehicles operate to determine potential EV replacement options, as well as infrastructure preparedness. The Company is utilizing its trip data, including mileage and location, to understand the best fit for each EV it is considering.

Q. Why is functional fit a critical part of the EV decision making process?

A. As with all other vehicles, the Company strives to ensure its Fleet aligns with industry best practices to serve the customer safely and efficiently. It will be important to consider, in addition to range, how an EV will support each department's ability to use it to its fullest capabilities, such as carrying tools and employees as required by the work.

Q. How will the Company determine if EVs are performing as expected?

A. The Company will be expanding its internal focus groups to provide real world feedback on barriers and opportunities to continuously improve how the Company adapts EVs in various operational environments. The Company will also study how EVs perform from a cost perspective, with lower maintenance and fuel costs expected.

Q. In what ways are EVs more beneficial than ICE vehicles?

A. Most of the benefits gained from utilizing EVs or battery-assisted systems arises from the changeover to electricity as the main source of energy, instead of gasoline or diesel fuels and petroleum-based maintenance materials. Electric motors require much less powertrain maintenance and repair, resulting in reduced maintenance costs, which is one of the key benefits of electrifying fleet units. A fully EV (battery) powered vehicle can also have up to 80% fewer parts than its ICE counterpart. With fewer internal parts, electric motors operate with less friction and more efficient use of energy. Many ICE vehicle parts require frequent and costly maintenance routines. Further, up to 65% of the heat energy produced by an ICE is wasted, requiring cooling systems which are prone to wear and eventual failure.

Q. Can you please give examples of reductions in maintenance that will arise out of a transition from ICE vehicles to EVs?

A. ICE vehicles contain hundreds of oil-lubricated parts that are required to convert the combustion of fossil fuels into the mechanical energy. Fluid changes extend to other components needed at various intervals in addition to engines and transmissions, including transfer cases and differentials throughout the life of all ICE vehicles. All these systems require regular maintenance and the associated costs in labor, parts, and materials to keep them at optimum performance and longevity. Over time, however, these components continue to wear even with diligent maintenance. This wear often leads to overheating issues, damaged or broken hoses, worn coolant pumps, or engine failure with the associated down time while undergoing repairs. EVs, on the other hand, do not require oil changes, spark plugs, fan belts, or tune ups. EVs also do not have transmission fluids that require periodic fluid changes, which makes them less prone to failure. Further, since an EV drive train requires less attention from a maintenance perspective, there is a reduced need for labor and/or material costs associated with this aspect of maintaining an EV. Plug-in EV hybrids often work with an ICE in conjunction with electric motors, reducing the fuel requirements for units equipped this way. Depending on the vehicle's configuration, a hybrid that features an ICE may need a maintenance schedule like a regular ICE vehicle; however, in most cases, plug-in hybrids help reduce overall fuel consumption with extended periodic maintenance requirements.

Q. Are there other tools available to reduce fossil fuel consumption in ICE vehicles?

A. Yes, there are idle-mitigation technologies, using plug-in battery systems, designed to reduce fuel consumption by reducing idle hours required to operate ancillary equipment such as a boom on a bucket truck. By employing a plug-in battery and electric motor, for example, ePTO units can power hydraulic systems for short periods, reducing fuel consumption and engine wear. When engaged at a jobsite, an ePTO system can shut an idling engine off, and a battery-powered motor then powers the hydraulics needed to position the boom and bucket, as well as powering the climate control system in the cab. As a result, the bucket truck will operate quietly while the operator performs work near a customer's home because the sound of an idling diesel will not be present while the ePTO system is engaged. The Company already employs this technology to help reduce idling hours on several specs that operate booms on bucket trucks and cabin climate control. Additionally, ePTO systems can reduce fleet's overall carbon dioxide tailpipe emissions, as well as diesel particulates.

Q. Has the Company undergone a concierge cost benefit analysis to help plan for internal EVs?

A. Per Case No. U-20963, the Company has partnered with CALSTART, a national non-profit with over 30 years' experience in the private and public sectors with a proven track record working with over 280 member companies and agencies to build business cases for clean transportation technology adoption. CALSTART is a nationally respected team of fleet electrification experts who were selected by the Company via a competitive Request For Proposal. CALSTART has completed numerous fleet electrification assessments for external customers, in addition to the Company's. The assessments analyzed the Company's light duty fleet vehicles, by location, and daily miles driven to provide approximate load demand by location. EV location determination helps in understanding potential carbon emission avoidance and cost benefit analysis.

Q. Does the Company solely rely on the CALSTART assessments for determining what EV to purchase?

A. The Company does not rely solely on the assessment in its planning for EVs. CALSTART used the Company's own fleet-generated data to compile a list of recommendations for vehicle locations that are potentially suitable for electrification, the estimated load demand for those locations, and the associated charging information to support them. This information assists the Company during the decision-making process when considering EVs.

Q. What quantifiable benefits of electrifying vehicles did CALSTART's assessment determine?

A. CALSTART's assessment, noted above, concluded that the Company has the potential to lower fleet's overall fuel and maintenance costs by approximately 70%, excluding vehicle purchase price, combined over the lifetime of the vehicles that are electrified. The assessment also concluded that the Company could potentially reduce tailpipe emissions by approximately 90,000 metric tons.

Q. Did the assessments provide suggestions for EV infrastructure support?

A. The assessments provide specific location-based electric load demands estimates for the light duty EVs planned for replacement, as well as electricity as fuel cost estimates based on current mileage driven by ICE vehicles. For each service center/office location, the Company's ICE light-duty fleet data was analyzed for average daily miles driven and applied this information to determine the appropriate level of charger (Level 1 or Level 2) and the estimated corresponding energy demand for each vehicle. With this information, the Company can plan for the specific infrastructure electrical upgrades needed to support the installation of Electric Vehicle Supply Equipment ("EVSE") at respective service centers with a measure of predictability based on the information the Company's ICE fleet has generated.

Q. Is there a cost difference between EVs and conventional fossil fuel vehicles?

A. Depending on make, model, and mileage range ratings, the purchase cost for an EV can vary as compared to an ICE vehicle. Currently, there are usually higher purchase costs associated with EVs that are comparable to ICE vehicles used by the Company to service its customers, such as all electric pick-up trucks.

Q. Can you provide an example of a suitable EV for the Company?

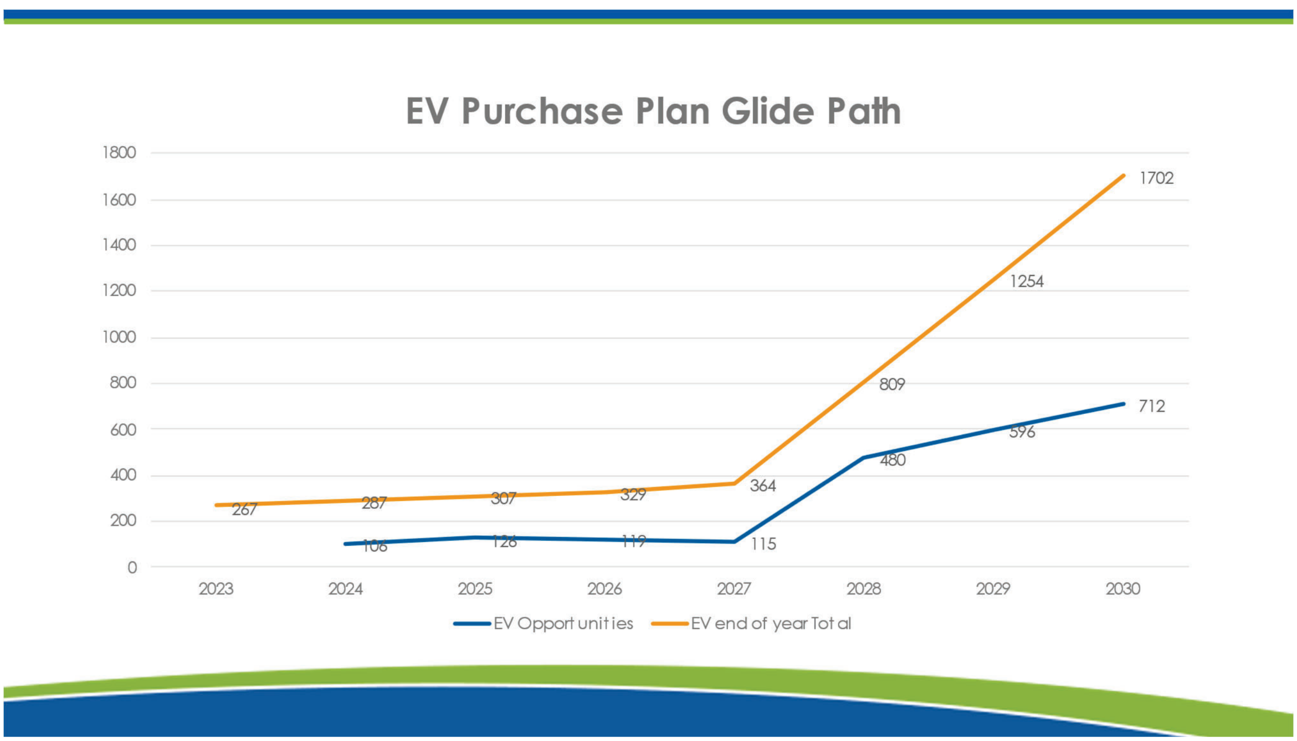
A. When considering an EV replacement, the Company seeks the closest EV equivalent to the out of lifecycle ICE under consideration for replacement. Currently, vehicles are more closely aligning with pickup trucks and economical sedans as most suitable for transportation and operational support.

Q. Are there other associated projects being planned to support vehicle electrification efforts?

A. Yes. To support the growth of EVs, the Company must plan for the increased electric load demands at most of its service centers to charge the EV units at those service centers. Since each center location will have a varying number of EVs and load demands, each location will require a specific power demand-based upgrade of its electric infrastructure for the installation of EVSE, also commonly known as "chargers." As noted earlier in my testimony, fleet has undergone a detailed data-based assessment to determine the load demands each facility will need to charge EVs daily.

Q. How many EV opportunities are identified in the Five-Year Purchase Plan?

A. The Five-Year Purchase Plan identifies approximately 450 potential opportunities to replace an ICE with an EV based on replacing units that have reached their end of life. As illustrated in the EV Purchase Plan Glide Path below, there are 106 light duty vehicles that could be replaced with an EV in 2024, and another 126 opportunities in 2025, 119 in 2026, and 115 in 2027. With limited opportunities to make ICE to EV replacements through 2027, the Company would need to invest additional funding above the currently approved capital replacement funding for the purchase of approximately 450 EVs over and above what the Purchase Plan identifies as a replaceable unit each year in 2028, 2029, and 2030 to reach the Company's goal of approximately 1,700 EVs.



Q. Is the market for vehicle electrification currently able to supply the vehicles needed to support the Company's goal?

A. Lead times for some EVs and vehicles equipped with idle mitigation systems are often two or more years out. The resources required by manufacturers to build enough units to meet high demand are not in alignment, which has often led to short supplies for both commercial and private customers; however, the market's availability of EVs suitable as fleet vehicles is still a relatively small part of the EV market. Currently, a substantial portion of the fleet EV market consists of vehicles that do not meet the criteria for cost and features best suited for use by the Company. For example, the Company prefers Original Equipment Manufacturer ("OEM") vehicles from Michigan-based companies, such as GM and Ford, as well as meeting all the requirements noted as part of the Fleet Electrification Filter. The recent fall in EV demand for EV pick-up trucks has shifted manufacturer focus to other models or delayed the development of new EVs. There are many startup companies with potentially viable EV units; however, the Company prefers to limit the potential exposure to the risks associated with startup company products.

Q. How does limited availability of EVs effect the Company's glidepath to its goal?

A. The Company's ability to increase the number of EV units in the fleet remains flat through 2027. At this time, limited market EV availability may prevent the Company from ordering the suitable number of EV units needed to affect a more linear glidepath toward the 2030 goal. Also, the EV opportunities identified in the Purchase Plan averages about 117 units per year. If the Company continues to purchase EV units at an average of 117 units per year, the goal to electrify 30% of the fleet will not be met by 2030.

Q. What EV units does the Company plan to purchase for the Test Year?

A. The Company is planning to replace nine ICE pick-up trucks with nine all electric Chevrolet Silverado EV pick-up trucks.

Q. How will the Company determine the locations to assign EV vehicles?

A. All EVs will be assigned to departments and teams that are best able to utilize the benefits of an EV during their daily job functions. As discussed earlier in my testimony, the assessment from CALSTART provides a summary of miles driven by location, allowing the Company to understand where an EV can be best utilized. For example, where the data shows an ICE pickup truck is typically driven 75 to 150 miles per day and returns to its respective service center, that vehicle could be eligible to be replaced with an EV of similar capability and range because the data suggests a good fit for an EV. The Company can reference the assessment data to help make the most informed decisions on their deployment. The Company also partners with operations to determine if an EV will meet the requirements of their work processes at a particular location.

Q. What associated infrastructure support will the EVs planned for the Test Year require?

A. The EV units will require chargers installed at their planned respective headquarters to support their charging requirements. The planned headquarter locations that will need EV chargers installed are as follows: Flint, Hamilton, Saginaw, Big Rapids, Norton Shores, Greenville, and Fremont.

Q. How does electrifying 30% of the Company's fleet by 2030 benefit the customer?

A. The Company's efforts to electrify a portion of the internal fleet will benefit the customer in several ways. The Company seeks to lower Fleet's overall operating costs by reducing its reliance on fossil fuels, which will bring lowered maintenance costs for reasons mentioned earlier in this testimony. By shifting the cost of refueling an ICE unit from gasoline or diesel to overnight charging, the Company can save money on fuel wherever mileage powered by fossil fuels can be shifted to lower cost charging overnight rates. Over the lifetime of these vehicles, by utilizing electricity to power 30% of the fleet, the Company seeks to leverage the relative stability and lower cost electricity offers over the more volatile cost of petroleum-based fuels and lubricants. Reducing the Company's reliance on ICE vehicles brings significant reductions in the maintenance costs associated with the upkeep of fossil fuel-based drivetrains. With fewer mechanical parts to maintain, EVs require lower maintenance budgets and fewer parts that can potentially fail over the lifetime of the vehicle.

Lastly, by lowering its reliance on fossil fuels, the Company seeks to lower its overall carbon dioxide emissions from Fleet's operations. Fully electrified vehicles have zero tailpipe emissions and, where applicable, hybrid vehicles and other technologies (like idle mitigating ePTO systems) also offer carbon reductions as well. Where idle mitigation systems are employed with diesel engines, reduced idling lowers particulates, or soot, generated with the combustion of diesel fuel. The Company's customers will benefit from the efforts to mitigate pollution, reduce greenhouse gas emissions, and lower its overall operating costs related to operating its internal fleet.

IV. FLEET SERVICES CAPITAL SPENDING PROJECTIONS

Q. Please describe the capital expenditures related to Fleet Services as shown on Exhibit A-12 (CEB-1), Schedule B-5.2.

A. Exhibit A-12 (CEB-1), Schedule B-5.2, provides gas Fleet Services capital spending, broken down into four capital spending categories: (i) Fleet Vehicle Capital Replacement, (ii) Fleet Vehicle Electrification, (iii) Fleet Business Partner Funded, and (iv) Fleet Tools - Garage. Exhibit A-12 (CEB-1), Schedule B-5.2, provides these capital expenditures with actuals for the 12 months ended December 31, 2023; projections for the 12 months ending December 31, 2024; 10 months ending October 31, 2025; 22 months ending October 31, 2025; and projections for the 12 months ending October 31, 2026, which is the test year in this case. For the historical year, 12 months ended December 31, 2023, the Company incurred Fleet Services capital expenditures in the amount of $9.405 million. The Company is projecting gas Fleet Services capital expenditures to be $9.925 million for the 12 months ending December 31, 2024; $7.048 million for the 10 months ending October 31, 2025; $16.973 million for the 22 months ending October 31, 2025; and $13.532 million in the projected test year ending October 31, 2026, as set forth in Exhibit A-12 (CEB-1), Schedule B-5.2, line 5, columns (b) through (f), respectively.

Q. Are there any contingency costs included in the Company's projected Gas Fleet Services capital expenditures?

A. No.

Q. What types of expenditures are included in Fleet Vehicle Capital Replacement Plan and Fleet Vehicle Electrification capital spending?

A. Details of the Fleet Vehicle Capital Replacement Plan are included in Exhibit A-28 (CEB-3). Fleet Vehicle Electrification expenditures include the additional cost of nine Chevrolet Silverado EV pickup trucks.

Q. What types of expenditures are included in Fleet Business Partner Funded?

A. Fleet Business Partner Funded expenditures include additional units purchased to support the Company's Advanced Methane Detection ("AMD") Systems, and one fully electric pick-up truck supporting PowerMIFleet education and outreach initiatives, both are described in detail later in my direct testimony.

Q. What types of expenditures are included in Fleet Tools?

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment to properly and safely service and repair fleet vehicles, equipment, and trailers. This is described in detail later in my direct testimony.

Q. How did you determine the appropriate distribution of capital costs among the cost categories shown on Exhibit A-12 (CEB-1), Schedule B-5.2?

A. As required by the Commission's filing requirements, the Company itemized the capital investments for Transportation Equipment by using the following cost categories: contractor, labor, materials, business expenses, and other. The Company breaks out these cost categories by calculating a five-year historical average of each of the Commission's prescribed cost categories from years 2019 and 2023 as a percentage of total Transportation Equipment investment over that same period. The five-year historical average for each cost category was then applied to the Transportation Equipment Program's projected capital spending for the bridge year and the test year to arrive at estimates for each cost category (i.e. contractor, labor, materials, business expenses, and other). This method is consistent for the projected test year presented in Exhibit A-12 (CEB-1), Schedule B-5.2.

A. Fleet Vehicle Capital Replacement Plan

Q. What level of Fleet Vehicle Capital Replacement Plan spending is proposed in this case?

A. As shown in Exhibit A-12 (CEB-1), Schedule B-5.2, the Company is proposing to spend $9.664 million in the 2024 bridge year; $6.605 million for the 10 months ending October 31, 2025; $16.269 million for the 22 months ending October 31, 2025; and $12.923 million in the 12 months ending October 31, 2026 test year on Fleet Vehicle Capital Replacement Plan spending.

Q. How did the Company determine its 2023 through 2026 Fleet Vehicle Capital Replacement Plan for the instant case, including the appropriate level of investment?

A. The Company is keeping Fleet Vehicle Capital Replacement Plan spending in 2023 through 2026 at historical spending levels, adjusted for inflation, based on what the Commission has previously approved for “lifecycle replacement spending.” By remaining at this level for 2023 through 2026, the Company is demonstrating its commitment to keeping costs affordable for customers. This set of vehicles was described earlier in my testimony, as shown in Exhibit A-28 (CEB-3).

Q How did the Company develop the list of vehicles that is projected to be purchased in years 2023 through 2026 of this case?

A. The specific units that the Company plans to purchase 2023 through 2026 are also shown in Exhibit A-28 (CEB-3). The Company produced an initial list of vehicles for replacement using the Blended Factor algorithm described earlier in my testimony, with a spreadsheet showing a Blended Factor percentage for each vehicle in the Company's fleet. This list was prioritized by the Blended Factor percentage to highlight vehicles that generate a positive (above 0.0%) percentage (the mathematical result of the Blended Factor calculation), which indicates that a vehicle has reached its expected life. Following the Blended Factor Analysis, as described previously in this testimony, the Replacement Plan filter included a review of market availability. By reviewing market availability, the Company can determine which replacement specifications can be expected for delivery through 2026. Vehicles that are likely not available for delivery in 2024 were not considered for replacement. To further refine the list of vehicles, standard crewing models were assessed. Though the Company will be continuing an analysis on right sizing, standard modeling helped guide the decision-making process.

Q. Was there additional analysis in determining the Fleet Vehicle Capital Replacement Plan for 2025 and 2026?

A. Yes. The list was further reviewed from a cost and utilization perspective. By assessing how often vehicles are used, the Company selected vehicles with a higher utilization rate when compared to similar specifications. The Company further narrowed the initial Blended Factor-based list based on fleet stakeholders' input on condition. In this step, vehicles were assessed by age, mileage, and overall condition, and associated operating costs and mechanical improvements, such as a newly installed engine. Vehicles that received recent substantial investments (new engines, for example) are removed from the potential replacement list because their expected life is generally extended following such investments.

Q. Does the Company anticipate variances in future fleet spending?

A. While the Company attempts to be as precise as possible in the Fleet Replacement Plan, there is the potential for variances slightly above or below projected budget due to the nature of the fleet business that includes supply chain challenges. However, the Company continues to be good stewards of the fleet by working to meet all projected expenditures as close to targeted goals as possible.

B. Fleet Vehicle Electrification

Q. In the projected test year, 12 months ending October 31, 2026, the Company is projecting an investment of $360,000 for EVs. What is included in this amount?

A. As shown in Exhibit A-12 (CEB-1), Schedule B-5.1, the Company is proposing to spend $360,000 in the 12 months ending October 31, 2026 test year on Fleet Vehicle Electrification.

Q. What kind of purchases are included in Fleet Vehicle Electrification?

A. As shown in Exhibit A-28 (CEB-3), line 3, column (b), Fleet Vehicle Electrification purchases include nine Chevrolet Silverado EV pickup trucks.

Q. Why are the expenditures presented for Fleet electrification appropriate?

A. Fleet expenditures requested will be used to bridge the price gap difference between a standard ICE pickup truck and a plug-in EV pickup truck of similar function. The proposed spending would fund the purchase price difference between a standard ICE pickup truck and its EV equivalent, which in this case is a Chevrolet Silverado EV. The purchase price difference between an ICE pickup truck chassis and an EV pickup truck chassis is approximately $40,000, totaling approximately $360,000 for nine Chevrolet Silverado

EVs. The addition of these EVs will further the Company's efforts to reduce fuel and maintenance costs, as well as its overall carbon footprint.

Q. Why is the Company requesting only the purchase price difference between an ICE vehicle and an EV in this case?

A. Due to these vehicles being part of the replacement plan process, the funding to replace an ICE chassis is already being requested as part of the capital replacement plan. Therefore, the Company is only requesting to add the purchase price difference between a standard ICE chassis and the electrification cost of its replacement unit.

Q. How do these capital expenditures benefit customers?

A. The expenditures in vehicle electrification will benefit the customer in several ways. EVs and plug-in hybrids are expected to lower the Company's overall fuel and maintenance costs as compared to ICE powered vehicles. The EVs proposed also offer significant potential reductions in greenhouse gas emissions, increasing the Company's carbon avoidance efforts, while providing service to customers with less pollution at lower cost. Lastly, the units proposed for the Test Year will further the Company's learnings on EV best practices, planning, and deployment as it increases fleet electrification.

C. <u>Fleet Business Partner Funded</u>

Q. In the 12 months ending December 31, 2023, the Company funded a partner -funded investment of $160,000. What is included in this amount?

A. As shown in Exhibit A-12 (CEB-1), Schedule B-5.2, line 3, column (b), the Company invested approximately $160,000 to fund one fully electric pick-up truck supporting PoweMIFleet education and outreach initiatives funded by that pilot, as well as three SUVs with AMD Systems for the Gas Strategy department within Gas Engineering and Supply.

Q. How did you determine the needed level of spending for the partner funded equipment?

A. A low-cost electric truck configuration from a Michigan-based manufacturer was selected that would have sufficient range for engaging at customer outreach events and discussions on electrification with fleets considering electrification. The vehicles purchased for AMD are suitable for advanced leak surveying requirements to provide vehicles that are capable of safely and efficiently transporting the driver and sensitive methane diagnostic and detection measuring equipment.

Q. How do these capital expenditures benefit the customers?

A. EVs are a technology change for almost all fleet customers. Given this, being able to see and experience an EV is important for customer education regarding infrastructure and charging requirements. Furthermore, by Consumers Energy modeling electric fleet adoption, customers have more confidence in the information being received from PowerMIFleet.

Q. Has the Commission previously approved spending for this partner-funded equipment?

A. Yes. The Commission approved spending for PowerMIFleet administration and customer outreach in its Order in Case No. U-20697.

Q. What concerns does Fleet Services have if the proposed capital expenditure amounts for expansion are not approved?

A. Presently, Consumers Energy has two smaller sedan EVs (i.e. Chevy Bolts) that are utilized for customer events and educational outreach. With a limited light duty fleet, the Company loses the ability to expand its education internally as well as externally. Data points from expanding into a larger class vehicle can educate the Company about return-on-investment potential and the ability to serve during normal and critical operations.

In addition, the state-of-the-art methane detection equipment used for AMD requires a reliable, robust platform to function optimally. The vehicles selected to be used in conjunction with this equipment provide the appropriate space to operate the equipment but also allows for the room required to service and repair the mobile lab the units must carry to perform the task. If investments are not made to purchase the units supporting the AMD Systems, the Company will not be able to implement and take advantage of the AMD's benefits.

D. <u>Fleet Tools</u>

Q. What kind of purchases are included in Fleet Tools?

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment required to properly service and repair fleet vehicles, equipment, and trailers.

Q. What level of expenditures is included in this rate case for Fleet Tools?

A As shown in Exhibit A-12 (CEB-1), Schedule B-5.2, the Company is proposing to spend $238,000 in the 2024 bridge year; $203,000 for the 10 months ending October 31, 2025; $441,000 for the 22 months ending October 31, 2025; and $249,000 in the 12 months ending October 31, 2026 test year on Fleet Garage Tools. A further breakdown of this tooling type per year can found on Exhibit A-29 (CEB-4).

Q. Why are the expenditures presented for Fleet Tools appropriate?

A. To properly repair vehicles in a compliant, safe, and efficient manner, it is necessary to have the right tool for the task at hand. The tooling can be anything from diagnostic tooling, electronic service information, tool sets, or a new air conditioning recovery/recycle/recharge machine required to properly service R1234yf refrigerant. Diagnostic tooling is necessary for the repair of most vehicle systems such as the engine, transmission, air bag, lighting, and anti-lock brakes. This tooling requires updates to maintain access to new vehicle models. Electronic service information is required to diagnose vehicle concerns and to follow the manufacturer's recommended repair procedures. Additional tooling such as hydraulic torque wrenches are critical in ensuring that high torque fasteners requiring very high torque applications are properly set and adjusted to manufacturer torque specifications to ensure safe repairs and inspections. Maintenance equipment, such as an R1234yf air conditioning machine, are required to meet Environmental Protection Agency standards for safely recovering and recharging air conditioning systems on newer model year vehicles.

Q. What benefits does this level of Fleet Tools spending provide to customers?

A. Across the state, the Company has 36 locations where Fleet mechanics are permanently stationed to perform their daily work. The Company also has remote sites, training facilities, and jobsite reporting locations where repairs to vehicles and equipment are also performed. The projected Fleet Tools for 2025 spending is approximately $494,000 for the entire Company, or approximately $13,700 for each of the 36 locations where mechanics are stationed. The gas allocation of this total is approximately $244,000. Each year, the Company replaces, and updates outdated or unrepairable shop equipment such as floor jacks, diagnostic equipment, tire machines, and welders. The benefit to customers of having tools in good order is less downtime for vehicles and reduced maintenance expenses because the Company is not solely reliant on outside repair shops to complete work needed to keep vehicles active. Most repair and maintenance items are performed by the Company's in-house mechanics; therefore, it is imperative that the Company maintain a complete and updated inventory of tools to complete the work required.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

DIRECT TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Marc R. Bleckman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Financial Planning and Analysis.

Q. What are your current responsibilities?

A. My responsibilities include preparation of the monthly forecasts, annual budgets, and long-term financial plans for Consumers Energy and CMS Energy, the parent company of Consumers Energy. As a part of my role, I conduct financial analyses and studies required for making various strategic decisions such as equity issuance, sale of businesses, and new investments. I assist the Chief Financial Officer in preparing the presentations for Board of Directors meetings, quarterly earnings calls, investor meetings, and industry conferences. My responsibilities also include preparation of the Renewable Energy Plan ("RE Plan") forecast model, which is a responsibility I have continued to assume from a previously held position.

Q. Please describe your educational background and describe any positions held prior to your current position.

A. I received a Master of Business Administration Degree with a Finance concentration from the Katz Graduate School at the University of Pittsburgh in 2002. Upon receiving this degree in May 2002, I joined Ford Motor Company ("Ford") as a Financial Analyst. During my seven years of employment at Ford, I worked in various finance roles throughout the company, including Assembly Operations, Powertrain Operations, Ford

Motor Credit, and the General Auditor's Office. My responsibilities within these organizations included, but were not limited to, forecasting of and variance reporting on, all Income Statement and Balance Sheet line items, as well as business process auditing. In July 2009, I left Ford to join Consumers Energy as a Principal Financial Analyst in the Company's Risk, Strategy, and Financial Advisory Services group. My responsibilities in this role included, but were not limited to, supporting the financial analysis and forecasting of the Company's renewable energy development plans, as well as conducting the Company's Enterprise Risk Management Program. In September 2012, I took on the role of Manager of Earnings Analysis in the Company's Financial Planning and Analysis Group. I assumed my current position as the Executive Director of Financial Planning and Analysis in February 2016.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in:

- Case No. U-16543, the Company's 2011 Application to Amend the RE Plan;
- Case No. U-16581, the Company's 2011 Application for biennial review of the RE Plan;
- Case No. U-17301, the Company's 2013 Application for biennial review of the RE Plan;
- Case No. U-17752, the Company's 2015 Application to Amend the RE Plan;
- Case No. U-17792, the Company's 2015 Application for biennial review of the RE Plan;
- Case No. U-18231, the Company's 2017 Application for biennial review of the RE Plan;
- Case No. U-20322, the Company's 2018 Gas Rate Case;
- Case No. U-20483, the Company's RE Plan reconciliation proceeding for 2018;

- Case No. U-20650, the Company's 2019 Gas Rate Case;
- Case No. U-20697, the Company's 2020 Electric Rate Case;
- Case No. U-20722, the Company's RE Plan reconciliation proceeding for 2019;
- Case No. U-20963, the Company's 2021 Electric Rate Case;
- Case No. U-20984, the Company's RE Plan amendment proceeding for 2021;
- Case No. U-21009, the Company's RE Plan reconciliation proceeding for 2020;
- Case No. U-21148, the Company's 2021 Gas Rate Case;
- Case No. U-21197, the Company's RE Plan reconciliation proceeding for 2021;
- Case No. U-21224, the Company's 2022 Electric Rate Case;
- Case No. U-21308, the Company's 2022 Gas Rate Case;
- Case No. U-21352, the Company's RE Plan reconciliation proceeding for 2022;
- Case No. U-21374, the Company's Application for approval of revised Voluntary Green Pricing programs and a RE Plan amendment;
- Case No. U-21389, the Company's 2023 Electric Rate Case;
- Case No. U-21490, the Company's 2023 Gas Rate Case;
- Case No. U-21549, the Company's RE Plan reconciliation proceeding for 2023;
- Case No. U-21585, the Company's 2024 Electric Rate Case; and
- Case No. U-21816, the Company's RE Plan amendment proceeding for 2024.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present my recommendations regarding the capital structure and cost of capital which should be used in computing the overall rate of return for Consumers Energy.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. <u>SUMMARY OF RECOMMENDATIONS</u>

II. <u>CAPITAL STRUCTURE AND COST RATES</u>

A. <u>Development of Capital Structure</u>

B. <u>Development of Cost Rates</u>

III. <u>EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS AND RECENT UTILITY BOND ISSUANCES</u>

IV. <u>PROJECTED CASH BALANCE</u>

V. <u>SUMMARY AND CONCLUSIONS</u>

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-14 (MRB-1)	Schedule D-1	Overall Rate of Return Summary;
Exhibit A-14 (MRB-2)	Schedule D-1a	Capital Structure Development;
Exhibit A-14 (MRB-3)	Schedule D-1b	Comparison of Development of Capital Structure;
Exhibit A-14 (MRB-4)	Schedule D-2	Cost of Long-Term Debt;
Exhibit A-14 (MRB-5)	Schedule D-3	Cost of Short-Term Debt;
Exhibit A-14 (MRB-6)	Schedule D-4	Cost of Preferred Stock;
Exhibit A-14 (MRB-7)	Schedule D-6	Short-Term Debt Utilization;
Exhibit A-30 (MRB-8)		Current and Historical Credit Ratings;
Exhibit A-31 (MRB-9)		Recent Utility Corporate Bond Issuances;
Exhibit A-32 (MRB-10)		Peer Company Commission Authorized Equity Ratios;
Exhibit A-33 (MRB-11)		State Regulatory Evaluations;
Exhibit A-34 (MRB-12)		Wells Fargo December 8, 2023 Report – Figure of the Week: Approved Equity Ratios, 2005-2023;

Exhibit A-35 (MRB-13)	Cumulative Annual Interest Savings;
Exhibit A-36 (MRB-14)	S&P Global August 7, 2024 Report – RRA State Regulatory Evaluations – Energy;
Exhibit A-37 (MRB-15)	UBS May 10, 2023 Report; and
Exhibit A-38 (MRB-16)	S&P February 14, 2024 Report.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

I. SUMMARY OF RECOMMENDATIONS

Q. What capital structure are you recommending be utilized in the overall rate of return calculation?

A. I am recommending that the capital structure shown on page 1 of Exhibit A-14 (MRB-1), Schedule D-1, be used in this case. This represents the actual capital structure as of December 31, 2023, adjusted for the projected changes in debt, equity, deferred income taxes, and Investment Tax Credit ("ITC") through the end of the test year ending on October 31, 2026. The development of the capital structure on a ratemaking basis is shown in columns (b) through (d). The equity ratio as a percentage of permanent capital is 50.75%. The equity ratio as a percentage of total capital is 42.58%.

Q. What Return on Equity ("ROE") are you assuming to determine the overall cost of capital for Consumers Energy?

A. I am assuming an ROE for Consumers Energy of 10.25%. This ROE is recommended by Company witness Ann E. Bulkley and supported in further detail in her direct testimony.

Q. What is the overall rate of return for Consumers Energy that you recommend be used in this case?

A. I am recommending an overall rate of return of 6.22% on an after-tax basis. This overall rate of return is the result of combining the capital structure and cost rates shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. The cost of the components and the weighted cost are shown in columns (e) through (i). The overall rate of return that I am recommending is the weighted cost of the various components of the capital structure.

II. CAPITAL STRUCTURE AND COST RATES

A. Development of Capital Structure

Q. What is capital structure?

A. Capital structure refers to the amounts and mix of a company's financing components which make up the funds used for its operations and capital investment. For the Company, this includes long-term debt, common equity, preferred equity (or preferred stock), short-term debt, ITC, and deferred income taxes.

Q. What is long-term debt and short-term debt?

A. Long-term debt consists of loans that have a due date (or maturity) that is more than one year from the date of issuance. For the Company, long-term debt consists exclusively of First Mortgage Bonds. Short-term debt represents borrowings that are short-term in nature (less than one year), and includes borrowings under the Company's credit facilities, including commercial paper and intercompany borrowings. The Company aims to finance its long-term capital (such as plant and property) with long-term debt and equity, and to finance short-term capital requirements (such as seasonal working capital needs) with short-term debt. This financing strategy is explained in more detail later in my direct testimony.

Q. What is common equity and preferred equity?

A. Equity is the net worth (assets minus liabilities) of a company. Common equity increases with net income (retained earnings) and with equity contributions from the Company's parent, CMS Energy. Common equity decreases when the Company makes dividend distributions to CMS Energy. Preferred equity is distinguished from common equity in that there is a fixed preferred dividend rate on preferred stock. Also, preferred equity has a higher ("preferred") claim to the Company's net assets in the event of insolvency.

Q. Do taxes play a part in the capital structure?

A. Yes. Deferred taxes and ITC represent reported book taxes that, due to special Internal Revenue Service deductions, measurements, or treatments, will not have to be paid until sometime in the future. This represents a temporary "zero cost" source of funding for the Company and is included as a component of the capital structure.

Q. How did you develop the long-term debt, preferred stock, common equity, short-term debt, deferred income tax, and ITC balances in the capital structure?

A. I started with the actual balances of long-term debt, preferred stock, common equity, short-term debt, deferred income taxes, and ITC as of December 31, 2023, as shown in Exhibit A-14 (MRB-2), Schedule D-1a, page 1, column (e). I then made the adjustments shown in column (f) to arrive at the average test year balance ending October 31, 2026, in column (g) that I am recommending be used in this case.

Q. Please explain the common equity adjustment of $2.291 billion.

A. I have projected that the 13-month common equity balance for the test year will be $2.291 billion higher than the December 31, 2023 balance. The common equity adjustment of $2.291 billion consists of two components. The first is an adjustment to reflect $466 million in projected retained earnings on a weighted average basis from January 2024 through October 2026. The second is an adjustment of $1.825 billion to reflect the projected equity infusions on a weighted average basis from January 2024 through October 2026.

Q. What are retained earnings?

A. Retained earnings are a company's net income from operations and other business activities retained by the company as additional equity capital. Retained earnings are, thus, a part of stockholders' equity.

Q. Please explain the retained earnings adjustment of $466 million.

A. Since I started with the December 31, 2023 balance for common equity, it was necessary to make an adjustment to reflect the increase in the common equity balance through retained earnings that will occur on a weighted average basis through October 31, 2026.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2024 through December 2024.

A. For the period of January 2024 through September 2024, I relied on actual changes in regulatory retained earnings. For the period of October 2024 through December 2024, I assumed the change in retained earnings would be equal to the actual change in retained earnings for the same months in 2023.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2025 through the test period ending October 2026.

A. Consumers Energy has a long-standing policy of using an 80% dividend payout ratio. I assumed Consumers Energy's retained earnings rate to be $14.417 million per month, or $173.0 million per year, from January 2025 through October 2026.

Q. Please explain how you arrived at Consumers Energy's retained earnings rate of $173.0 million per year.

A. Based on Consumers Energy's Securities and Exchange Commission Form 10-K for 2023, I determined that Consumers Energy's net income for the 12-month period ended December 31, 2023, was $865 million. I used this amount as a proxy for the future net income and assumed a dividend payout ratio of 80%. Using these assumptions, I calculated an annual retained earnings amount of $173.0 million [$865 x (1-0.80)]. Exhibit A-14 (MRB-2), Schedule D-1a, page 3, shows the projected monthly retained earnings balance and calculates the 13-month average for the period ending October 31, 2026.

Q. What are equity infusions?

A. Equity infusions are cash investments made by CMS Energy into Consumers Energy, thereby increasing the Company's common equity balance.

Q. Why did you make a $1.825 billion adjustment for the new equity infusions in your recommended capital structure?

A. This is the amount needed to hold a 50.75% equity ratio for the test period in this case. CMS Energy made an equity infusion of $300 million in November 2024 and plans to make equity infusions of $115 million by December 2024, $450 million by February 2025, $475 million by June 2025, $450 million by February 2026, and $450 million by June

2026. Accordingly, I reflected this in the equity balance for the test year for this case on a weighted average basis. The impact of these equity infusions on the cumulative balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 3. The 13-month average for the period ending October 31, 2026, is $1.825 billion. When the 13-month average for the equity infusions of $1.825 billion is combined with the 13-month average $466 million retained earnings adjustment, the increase to equity capital is the $2.291 billion shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 1.

Q. How is your testimony structured with regards to the proposed equity ratio?

A. My testimony describing the key factors and providing evidence that supports the proposed equity ratio of 50.75% is organized as follows:

i. Peer Authorized Equity Ratios are Higher and Trending Up
ii. Equity Ratio / ROE Impact on Credit Quality
iii. Rating Agencies' Assessment of the Regulatory Environment
iv. Credit Challenges Facing Regulated Utilities

i. Peer Authorized Equity Ratios are Higher and Trending Up

Q. How does the 50.75% equity ratio proposed in this case compare to other utilities?

A. To compare the 50.75% equity ratio proposed in this case to other utilities, I researched all rate case decisions of peer companies from 2020 through September 2024 and determined the authorized or approved equity ratio for each. This is reflected on Exhibit A-32 (MRB-10). Peer companies for this analysis is defined as regulated subsidiaries of the Company's ROE proxy group in Case No. U-21490, and excludes final orders received by in-state proxy DTE Energy Company as well as the Company. The average equity ratio for the peer group was 54.05%, 330 basis points higher than the 50.75% proposed for Consumers Energy in this case.

Q. Are the equity ratios reflected in your sample based on reported financial data or Commission-authorized equity ratios in regulatory proceedings?

A. The equity ratios were taken from Commission orders and public filings and represent actual regulatory equity ratios authorized or approved by different commissions across the country. It is clear from this analysis that, on average, regulatory commissions of the Company's peer group are granting equity ratios that are much higher than the 50.75% that is proposed by the Company in the current case.

Q. Are the utilities included in Exhibit A-32 (MRB-10) companies at the parent holding company level or the regulated subsidiary level?

A. The utilities included in Exhibit A-32 (MRB-10) are at the regulated subsidiary level. This is important because Consumers Energy is a regulated subsidiary; therefore, the comparison to the average commission-authorized equity ratios also needs to be at that same level in order for the analysis to be a valid comparable benchmark in this case.

Q. Is it appropriate to use equity ratios at the parent holding company level in order to determine the average "peer group" equity ratio for the Company in this case?

A. No. Companies at the parent holding company level should not be considered "peers" for purposes of determining the average equity ratio for the Company's peer group. This would be a misleading comparison since equity ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items. In addition, an analysis of equity ratios at the parent holding company level may also be skewed since the source for this data is most likely Securities and Exchange Commission reported financial statements, which are prepared under Generally Accepted Accounting Principles ("GAAP"). There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis which would further distort the equity ratios calculated at the parent holding company level.

Q. Has the Commission addressed the fact that an analysis of equity ratios at the parent holding company level is not appropriate?

A. Yes. In its Order in Case No. U-20963, the Commission stated that "regulatory and financial data should not be combined" with such an analysis. Further, the Commission deemed that such an analysis is invalid assuming one "could not verify that its data contained equity ratios set by a regulatory commission in a rate case." It is clear from the Commission's Order that actual commission authorized equity ratios at the regulated subsidiary level as presented in Exhibit A-32 (MRB-10) is the preferred data source for an analysis comparing relative equity ratios of peers.

Q. How does the trend in the Company's authorized equity ratio compare to other utilities?

A. Equity ratios for regulated utilities have increased over the last several years. This trend was highlighted in a December 2023 Wells Fargo report on approved equity ratios. See Exhibit A-34 (MRB-12). As described in the Company's testimony in previous rate cases, negative cash flow and credit metric impacts occurred when federal tax changes took effect in 2018. In subsequent years, utility commissions adopted higher equity ratios as one way to combat those impacts. The Wells Fargo report shows an increase in approved electric utility equity ratios of 130 basis points from 2019 to 2023. In contrast, the Company's authorized equity ratio has <u>decreased</u> 262 basis points from 2019 to present, weakening credit quality and putting the Company's credit rating at risk. The Company has presented data showing that peer authorized equity ratios are significantly higher and are trending up. While this data indicates that a higher equity ratio is warranted, the Company is proposing an equity ratio of 50.75% in this case. This is the minimum amount that, taken together with an ROE of 10.25%, reflects the appropriate level that the Commission should adopt to help preserve Consumers Energy's current credit rating.

ii. Equity Ratio / ROE Impact on Credit Quality

Q. How does the equity ratio approved in this case impact the Company's credit metrics and credit quality?

A. A key financial metric used by rating agencies is the ratio of Funds From Operations ("FFO") to Debt ("FFO-to-Debt ratio"). The calculation of this financial metric includes, in part, both the equity ratio and the authorized ROE of the Company; thus, there needs to be a balance between the Company's equity ratio and ROE that will ensure that this key financial metric does not degrade and cause significant credit deterioration. An equity ratio of 50.75% and an ROE of 10.25%, as recommended by the Company in this case, results in an FFO-to-Debt ratio that is sufficient in striking this balance.

Q. What is an FFO-to-Debt ratio?

A. An FFO-to-Debt ratio is a financial metric that compares a company's cash flow from operating activities to a company's leverage, or debt outstanding. It can also be described as a type of payback ratio, reflecting the Company's ability to repay its outstanding debt with operating cash flow. A higher FFO-to-Debt ratio, one which reflects a higher level of cash flow from operating activities to offset or otherwise reduce the risk associated with the Company's ability to pay its debts, is viewed favorably and indicative of a lower financial risk and a resulting higher relative credit rating. A higher credit rating, in turn, results in lower financing rates. This is comparable to a bank's credit evaluation for someone requesting a personal loan. After reviewing personal income and outstanding debt, banks generally offer lower financing rates to individuals who have more cash flow to repay debt, indicating a relatively higher credit quality.

Q. Discuss the relationship between the Company's ROE, its equity ratio, and the Company's credit metrics.

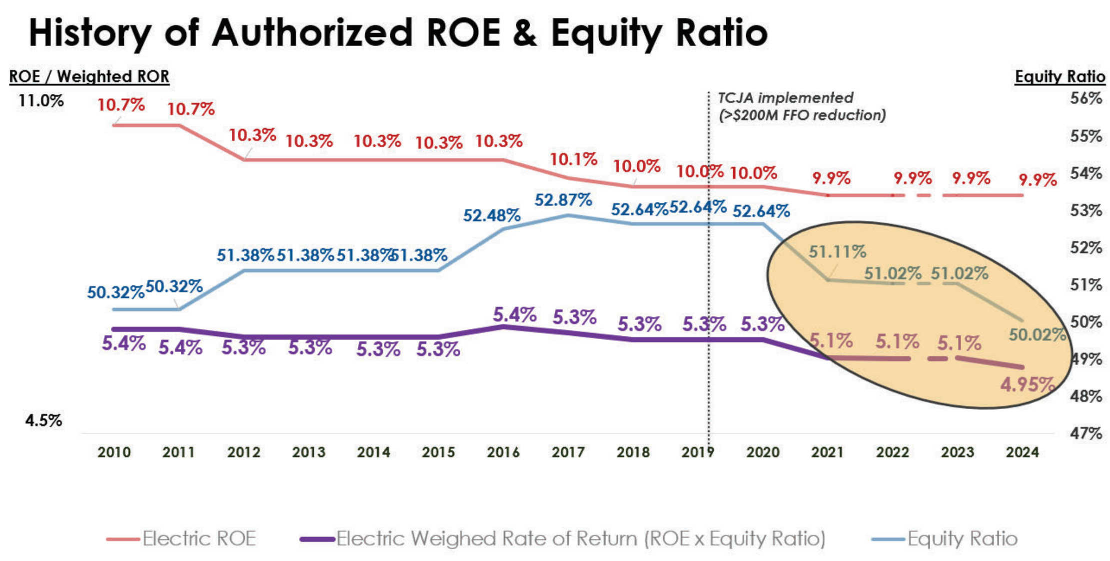
A. As discussed earlier in my testimony, ROE and equity ratio are two inputs in determining the Company's ratio of FFO to Debt, and FFO-to-Debt ratios are used by credit agencies to determine the Company's financial health. Consequently, it is important to recognize that the Company's ROE and equity ratio cannot be evaluated in isolation, but should, instead, be viewed as interconnected components that determine the Company's overall financial health. An ROE of 10.25%, when taken <u>together</u> with an equity ratio of 50.75% results in an FFO-to-Debt ratio that the Company believes is acceptable in the current case and is responsive to recent Commission orders. A lower authorized ROE would, therefore, necessitate a higher approved equity ratio to maintain the same level of financial health.

Q. How can the combined cost of a Company's equity ratio and ROE components be properly evaluated?

A. Multiplying the equity ratio by the ROE produces a weighted cost or "rate of return." This is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. On line 6 of this exhibit, the equity ratio of 50.75% from column (c) is multiplied by the ROE of 10.25% from column (e) to produce a weighted cost of 5.20%, shown in column (f). This is the weighted cost of common equity, a component of the Company's overall rate of return. This rate of return is important to consider since it takes into account the equity ratio in combination with the ROE. As discussed earlier in my testimony, the 50.75% equity ratio and 10.25% ROE is a combination that the Company believes is acceptable in the current case.

Q. What has been the recent trend of the Company's weighted rate of return?

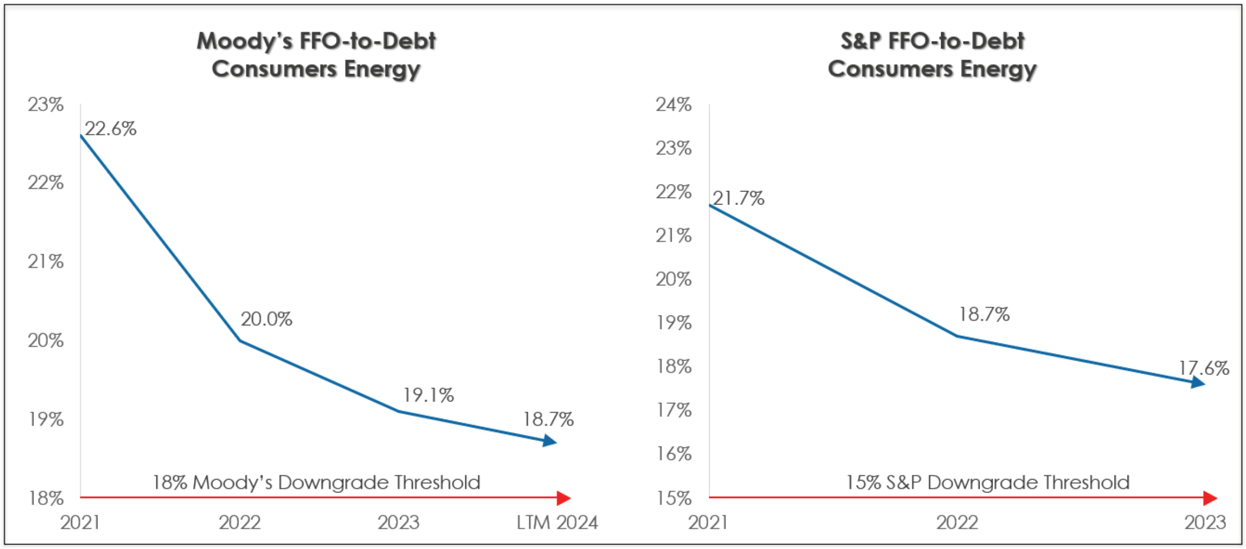
A. Following a long period of stability, recent rate cases have resulted in a sharp decline in rate of return. This is illustrated in the following chart which includes a history of electric authorized ROE, equity ratio, and resulting weighted rate of return.



Q. What has been the trend of the Company's credit metrics over the last few years?

A. The Company's FFO-to-Debt ratio as calculated by S&P has been trending down in recent years from 21.7% in 2021 to 17.6% in 2023, a decrease of 410 basis points and, for 2023, 40 basis points <u>below</u> the low end of S&P's expected range outlined in its 2023 report. In addition, the Company's FFO-to-Debt ratio as calculated by Moody's has also been trending down in recent years from 22.6% in 2021 to 19.1% in 2023, a decrease of 350 basis points. Moody's May 2024 credit report also shows a further decline to 18.7% for the 12 months ended March 2024. The Company's FFO-to-Debt ratio as calculated by Moody's is trending down and was well below the low end of Moody's expected range

(20-21%) for the Company for 2023 and through the first quarter of 2024. These credit metric results are shown in the following chart:



As explained earlier in my direct testimony, recent rate cases have resulted in a sharp decline in rate of return (ROE multiplied by equity ratio). A reduction in the Company's rate of return lowers the Company's cash flow and FFO-to-Debt ratio. The Company also needs to increase its long-term debt to achieve a lower equity ratio. This increase in debt also weakens the Company's FFO-to-Debt ratio. These negative credit metric impacts place the Company's credit quality and credit ratings at risk.

Q. Should the potential for new tax legislation and the resulting deterioration of the Company's cash flow and credit metrics be considered in determining the appropriate ROE and equity ratio in this case?

A. Yes. I am generally aware that Donald Trump, the winner of the 2024 presidential election, has indicated his intent to advance legislation that would lower the corporate income tax rate from 21% to 15%. Republican congressional control should help to facilitate the passage of this legislation. President Trump executed a similar tax policy initiative in his first term which led to the passage of the Tax Cuts and Jobs Act of 2017 ("TCJA"), which reduced the corporate tax rate from 35% to 21%. As explained in my direct testimony in Case No. U-20322, the Company's 2018 gas rate case, the TCJA had direct and significant impacts on the Company's cash flow, resulting in a weakening of the Company's financial credit metrics. The Company's FFO was reduced by just over $200 million and, assuming approximately half of this reduction in cash is replaced with long-term debt, the Company's FFO-to-Debt ratio was reduced by 310 basis points. In addition, President Trump has indicated a desire to target portions of the Inflation Reduction Act of 2022 ("IRA") for repeal. Since aspects of the IRA allow for the Company to recognize cash proceeds from tax credit sales, this could also be detrimental to the Company's credit metrics. With these potential credit-harmful legislative actions looming during the test year of this case, it is especially important for the Commission to authorize an ROE and equity layer that will be supportive of the Company's credit quality. The authorized ROE and equity ratio are integral components of the Company's financial credit metrics and will be a key factor in combating the negative impacts of this potential tax legislation.

Q. In addition to tax reform, are there other aspects of President Trump's agenda that could have material impacts on the Company's credit metrics during the test year of this case?

A. Yes. From following the news during the election, I am aware that as a candidate, President Trump proposed a 60% tariff on goods from China as well as a 10% to 20% "universal" tariff on all imports, and also threatened a 25% tariff on Mexico, the United States' top trading partner. These tariffs, if enacted, could lead to disruption in the supply chain and a dramatic increase in the cost of materials, goods, and supplies. This, in turn could introduce significant regulatory lag in recovery of the Company's operations and maintenance ("O&M") and capital spending which would have a detrimental impact on credit metrics and credit quality.

Q. What are the customer benefits of the Company maintaining a higher credit rating?

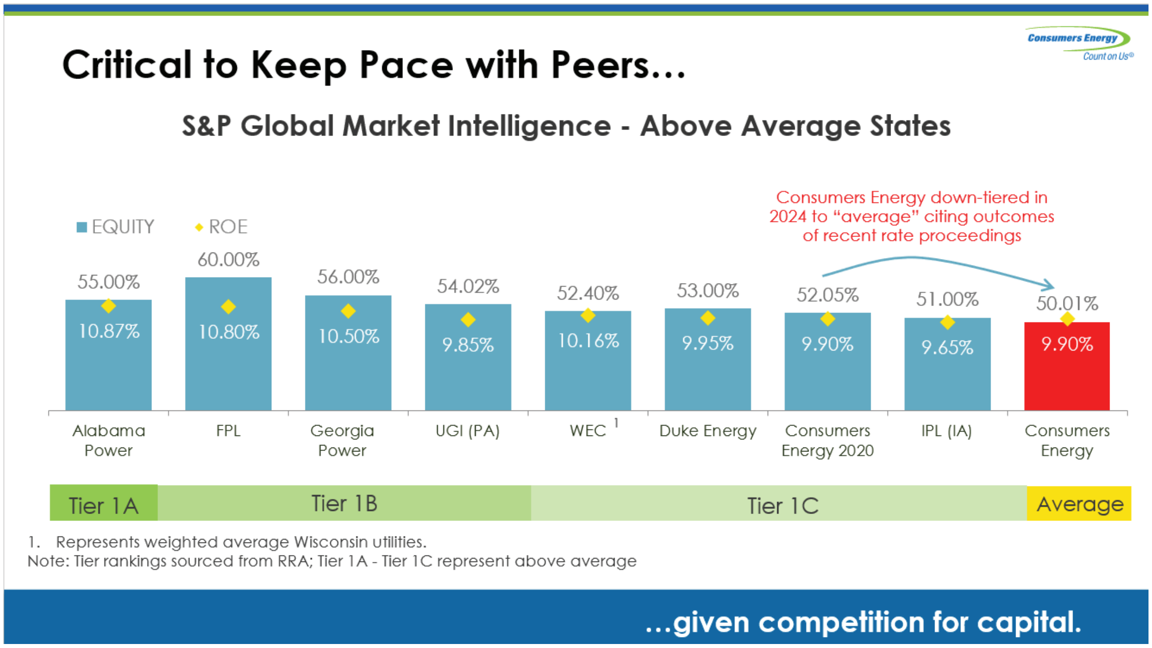
A. The Company provides a critical service that directly impacts customers' quality of life. The Company's ability to deliver long-term investments to the infrastructure that provide safe, reliable, and clean energy will depend on the financial strength of the Company, of which the Company's credit rating is a key indicator. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments to maintain and improve infrastructure to the benefit of customers. During this time, the Company will rely heavily on the capital markets to fund these investments. Generally, a higher credit rating results in lower financing rates. Therefore, it will be especially important for the Company to maintain strong credit ratings over this period. As shown in Exhibit A-35 (MRB-13), the Company has saved ratepayers $153 million annually as a result of improved credit ratings and lowered interest costs.

The common equity balance and equity ratio projected for the test year in this case also enable the Company to maintain strong credit ratings and better withstand any shocks in the financial markets. An example of this was in March 2023, when Silicon Valley Bank and Signature Bank collapsed, forcing the Federal government to step in and take over the banks. Silicon Valley Bank marked the biggest failure of a United States bank since the 2008 global financial crisis and led to significant market turmoil. Other large banks such as Credit Suisse and First Republic Bank also experienced significant financial pressure caused by the ensuing market panic. Strong credit ratings can help protect customers from spikes in interest rates which increase the cost of capital, and/or inaccessibility to the capital markets which serve as a key source of financing for the Company's investments on behalf of customers. Strong credit ratings can also enable the Company to issue long-term debt ahead of upcoming maturities ("pre-fund") to take advantage of low interest rates and favorable issuance windows without jeopardizing the Company's financial ratios. When market conditions are favorable, refinancing higher interest rate debt at lower rates reduces the Company's overall cost of capital included in customer rates.

iii. Rating Agencies' Assessment of the Regulatory Environment

Q. How else does the equity ratio and ROE impact the Company's credit quality?

A. One component of rating agencies' evaluation of credit quality involves an assessment of the Company's regulatory environment. If the Commission demonstrates a pattern of consistent, constructive rate orders, it contributes favorably to the Company's credit quality and credit rating. The authorized equity ratio and ROE are two important components in the rating agencies' assessment of the regulatory environment. Refer to Exhibit A-36 (MRB-14), S&P's State Regulatory Evaluations – Energy. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average." This is reflected in the following chart:



In downgrading its state regulatory rating, S&P referenced recent rate case decisions in Michigan including authorized ROEs which "compare less favorably" to prevailing industry averages and a "tightening in the regulatory climate." In recent rate case filings, the Company has included this chart, noting that the recent decline in the Company's weighted rate of return has led to the risk that the Company will no longer be ranked as a utility in an above-average tier jurisdiction. S&P's August 2024 report confirms that this has risk has been realized.

Q. Is there evidence that analysts have also started to recognize a decline in the state of the Company's regulatory environment?

A. Yes. In updating its regulatory rankings for U.S. utilities in May 2023, UBS downgraded Michigan from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs ranking in the 3rd quintile as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." Refer to Exhibit A-106 (MRB-15). It is apparent that rating agencies and analysts are taking note of the Company's regulatory outcomes and are viewing them unfavorably. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating. Michigan's above average regulatory standing needs to be protected and bolstered rather than leveraged to justify further credit deterioration and over-leveraging of the Company.

iv. Credit Challenges Facing Regulated Utilities

Q. Have rating agencies commented on the credit quality of regulated utilities as a whole?

A. Yes. In a February 2024 report "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens," S&P updated their outlook of the regulated utility industry to negative. S&P cites the high percentage of utilities with negative credit FFO-to-debt and the interrelationship between ROE, equity ratio, and credit metrics outlooks and expects that 2024 will likely be the fifth consecutive year that credit downgrades outpace upgrades. In its report (Exhibit A-107 (MRB-16)), S&P cites "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. S&P states that "for 2023, the industry's actual equity issuance was considerably below our expectations, resulting in a weakening of financial performance and credit quality. If this trend persists, credit quality will again likely experience pressure in 2024." S&P also notes utilities as having "strained financial cushion." Specifically, S&P states:

> About 35% of the industry is sustaining performance with minimal financial cushion, reflecting funds from operations (FFO) to debt that is less than 100 basis points (bps) above

> their downgrade threshold. The limited financial cushion affects a company's ability to absorb unexpected events beyond the base case for our ratings, increasing its susceptibility to a downgrade. [Exhibit A-107 (MRB-16), page 11.]

In addition, S&P cites the following credit headwinds impacting regulated utilities:

- Upcoming debt maturities amid higher interest rates, weakening financial performance;
- A narrowing spread between U.S. Treasuries and authorized ROE's which directly hinders the financial performance; and
- Elevated inflation rates resulting in higher costs that, given regulatory lag, could weaken financial performance.

S&P's assessment of the regulated utility industry was echoed by another credit rating agency, Fitch, in December 2023. In describing a "deteriorating outlook for North American utilities, power & gas in 2024," Fitch cited similar credit headwinds that are putting pressure on utilities' credit metrics. Specifically, Fitch concluded that "the sharp escalation in interest rates has significantly narrowed the headroom in FFO fixed-charge coverage for the sector."

As highlighted earlier in my testimony, there has been a sharp decline in the Company's authorized weighted rate of return following several years of consistent results. It is apparent from this S&P report that a supportive ROE and equity ratio is critical in maintaining a "financial cushion" to protect against downgrade in the event of unforeseen events like the market volatility and disruption that occurred during the onset of the COVID-19 pandemic in 2020 or the financial pressure caused by the dramatic increase in gas prices and interest rates in 2022 or the banking crisis of 2023. These events and rating agency comments highlight the importance for the Company to maintain strong financial metrics and to not manage toward the perceived low end of the credit metric bands. The

Company's ability to continue to provide customers with safe, reliable, and clean energy and make the necessary capital investments is directly tied to the Company's ability to maintain its financial strength.

Q. Is an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case the optimal outcome for the Company and its customers?

A. Yes. This equity ratio and ROE combination is well-measured for both the Company and its customers, while still mindful of the Commission's Order in Case No. U-21389. This results in a weighted rate of return of 5.20% (50.75% x 10.25%), which is 25 basis points higher than the weighted rate of return of 4.95% (50.02% x 9.90%) approved in Case No. U-21389. This capital structure results in a reasonable impact on customer rates while bringing the Company more in-line with the authorized weighted rate of return experienced toward the beginning of the COVID-19 pandemic and prior to the most recent credit rating downgrade. The weighted rate of return as proposed in this case strengthens the Company's balance sheet and credit quality which will be critical in delivering the Reliability Roadmap investments while doing so in the midst of a sustained elevated interest rate environment.

Q. Please explain the long-term debt adjustment of $2.248 billion.

A. I have projected that the average debt balance for the test year ending October 31, 2026, will be $2.248 billion higher than the December 31, 2023 balance. This adjustment consists of the following components:

Long-Term Debt (in millions) Month	Issuance	Retirement	Oct. 31, 2026 Test Year Impact
Jan. 2024	$600	$0	$600
Aug. 2024	$700	$0	$700
Sep. 2024	$0	($250)	($250)
Dec. 2024	$0	($52)	($52)
May 2025	$475	$0	$475
Aug. 2025	$500	$0	$500
May 2026	$525	($115)	$189
Aug. 2026	$425	$0	$98
Subtotal			$2,260
Changes in Unamortized Fees			(12)
Total			**$2,248**

The development of the 13-month average long-term debt balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

Q. Please describe the planned debt issuances in May 2025, August 2025, May 2026, and August 2026.

A. Each of these planned debt issuances will be used for general corporate purposes of the Company including financing capital expenditures. The debt planned to be issued in May 2026 will also be used for the retirement of the Company's $115 million 5.24% bonds which mature in May 2026. These planned debt issuances have been determined based on the Company's financing plans after evaluating cash and liquidity requirements for the Company.

Q. What long-term debt was included in developing the 13-month average amount outstanding for the period ending October 31, 2026?

A. Exhibit A-14 (MRB-4), Schedule D-2, shows the long-term debt that was included in developing the 13-month average for the period ending October 31, 2026. The average amount outstanding on line 64, column (j), ties to the 13-month average balance shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

Q. What is your projection regarding the level of short-term debt balance for the test year ending October 31, 2026?

A. I have projected an average short-term debt balance for the test year of $201 million. This balance is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 10, column (b); Exhibit A-14 (MRB-2), Schedule D-1a, page 1, line 10, column (g); and Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 1.

Q. What are the components of the average short-term debt balance?

A. Revolvers, commercial paper, and intercompany borrowing are short-term financing options available to the Company. Revolvers are revolving lines of credit that allow the Company to borrow and repay as long as the outstanding balances remain within the credit limits, or capacity. Commercial paper represents debt issuances under the Company's Commercial Paper Program that are short-term in nature, typically 1- to 90-day maturities. Intercompany borrowing represents short-term borrowings from CMS Energy. Intercompany borrowing is drawn under a promissory note with CMS Energy up to $500 million and carries an interest rate of 1-month Secured Overnight Financing Rate

("SOFR")[1] minus 10 basis points. The Company is the beneficiary of intercompany borrowing to meet short-term liquidity needs when it is available and when it is the most cost-effective alternative. It should be noted that the intercompany borrowing facility is not a dedicated financing option that is always available for the Company to use, but only when CMS Energy has surplus cash and effective borrowing rates must be lower than rates available to the Company under the Commercial Paper Program. The intercompany borrowing facility, therefore, is not considered part of the total liquidity capacity available to the Company.

Q. How was the short-term debt balance of $201 million developed?

A. Exhibit A-14 (MRB-7), Schedule D-6, shows the projected balances, by month, of short-term debt for the test year ending October 31, 2026. I have arrived at these projections after considering the projected total monthly cash flow requirements, planned long-term debt (net) and equity issuances, and the amount of short-term financing available.

Q. Are the projections for short-term debt reflected on Exhibit A-14 (MRB-7), Schedule D-6, expected to be issued under the Company's revolvers, its Commercial Paper Program, or its intercompany borrowing agreement?

A. The Company borrows on its short-term financing facilities in order from least expensive to more expensive. The following is the prioritized order in which the Company utilizes its short-term financing facilities:

[1] SOFR, a benchmark interest rate used in calculating short-term variable interest rates throughout the world. SOFR replaced the London Interbank Offered Rate ("LIBOR") in 2023.

		Amount	**Credit Capacity**
1a. 1b.	Commercial Paper Intercompany Borrowing**	$500 million $500 million	$500 million*
2.	Scotiabank Revolver	$250 million	$250 million
3.	JPMorgan Revolver	$1.1 billion	$600 million*
	Total		$1.35 billion

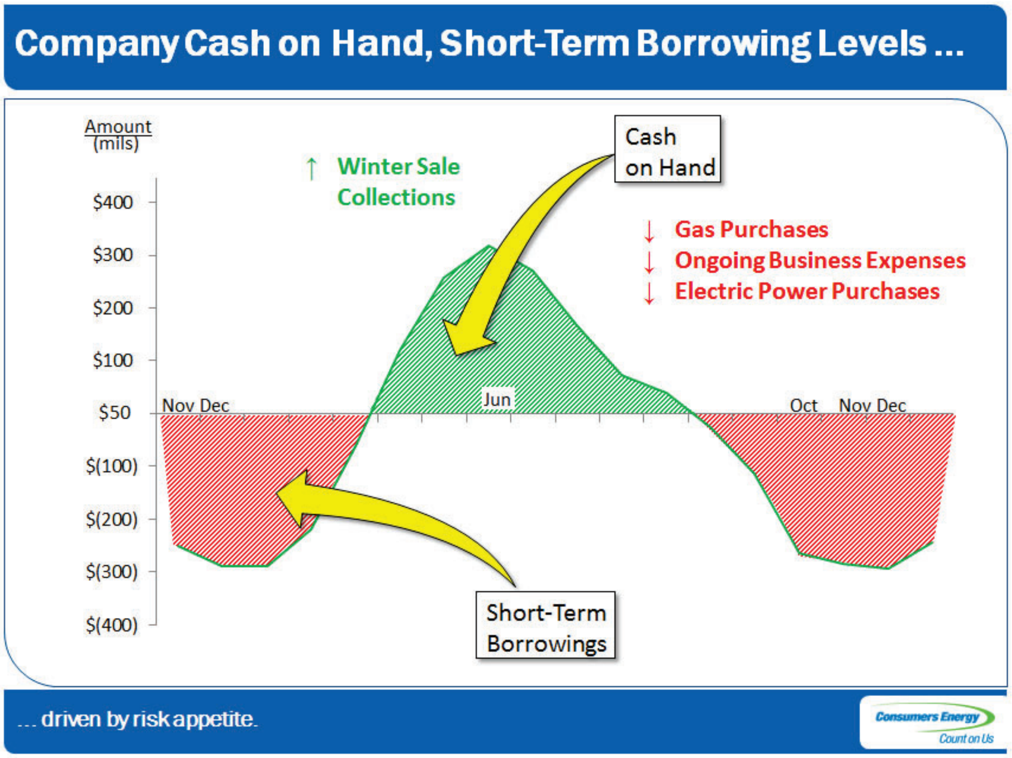
*Takes away $500 million of the JPMorgan revolver's $1.1 billion capacity (leaving $600 million available).

**Intercompany Borrowing or Commercial Paper is used first, depending on availability and which alternative is the most cost-effective at the time of borrowing.

All of the projected test year balances for short-term debt are assumed to be issued under the Company's Commercial Paper Program. This program, along with the intercompany borrowing facility, are the least expensive short-term financing options to the Company and are assumed to be used first when the need arises. The Company's $250 million Scotiabank revolving credit facility is the next least-costly, short-term financing option, with the remaining $600 million revolver ($1.1 billion total capacity less $500 million drawn commercial paper) assumed to be used last.

Q. How does the timing and amount of short-term borrowings fit into the Company's overall liquidity and financing strategy?

A. The Company strives to match long-term investments with long-term financing and to finance short-term liquidity needs with its cash and short-term borrowing facilities. The timing and amount of short-term borrowings is directly related to the level of cash on hand. Due to the seasonal nature of utility cash inflows and outflows, the Company generally holds more cash in the spring and summer months and relies on short-term borrowing in the fall and winter months. Throughout the year, however, a minimum level of cash on hand is maintained. This is reflected in the following chart which depicts the typical cash and short-term borrowing levels through a given year:



Q. In order to reduce costs, would the Company consider maintaining a permanent layer of short-term debt?

A. No. Short-term financing markets can be volatile and, at times, access to those markets completely disappear, as was witnessed during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil described earlier in my testimony. Based on the experience and judgment of the Company's Treasury Department, as well as members of the Financial Planning and Analysis Department, the Company does not pursue a strategy that maintains a permanent balance of short-term debt. However, the Company does fund seasonal fluctuations in its working capital with short-term debt as previously illustrated. Based on historical trends of these seasonal fluctuations, the difference between the maximum working capital surplus and the maximum level of working capital deficiency (peak-to-valley) is approximately $300 million to $600 million. The Company is generally comfortable financing between $200 million and $400 million of this gap with short-term borrowings as doing so leaves adequate undrawn capacity in the event of financial market volatility or disruption. In addition, rating agencies assess the Company's liquidity as a component of their overall credit rating methodology. Reducing cash balances and relying consistently on short-term borrowings would weaken the Company's liquidity metrics. Finally, if the Company were to establish and maintain a permanent level of short-term debt, this should be taken into account in calculating the appropriate equity ratio in this case. If the short-term debt balance were included in the debt-to-equity ratio calculation, the required equity balance would need to increase in order to achieve the appropriate 50.75% equity ratio. Doing so would result in a higher overall cost of capital.

Q. How does the Company balance the benefit of carrying sufficient liquidity with the cost of maintaining its short-term credit capacity?

A. The Company's projected $1.35 billion total short-term credit capacity is reasonable and necessary to conduct daily operations and also to keep credit risk at a reasonable level. To maintain strong financial health, it is important for the Company to maintain adequate short-term financing capacity for normal business operations while retaining an adequate amount of additional liquidity for cases of extreme market fluctuations or other unforeseen circumstances. As shown in Exhibit A-14 (MRB-7), Schedule D-6, the Company projects up to $490 million of short-term borrowings, utilizing most of the $500 million capacity of the Commercial Paper Program. Access to the commercial paper market, however, requires an equivalent amount of revolving credit capacity as a “backstop”; therefore, of the Company’s $1.35 billion of revolving credit facilities, $500 million is used to support commercial paper issuance. The remaining $850 million of revolver capacity is a vital backstop for capital expenditures and upcoming long-term debt maturities.

Q. Did the dramatic increase in natural gas prices in 2022 serve as an example of the importance of the Company holding sufficient short-term credit capacity?

A. Yes. The Company generally funds its natural gas purchases using short-term borrowing. Surging demand in the United States combined with national inventory levels below historical averages drove gas prices higher in 2022. In addition, Russia’s invasion of Ukraine and the related energy market disruptions further increased gas prices. As a result, the Company had to purchase natural gas at significantly higher prices. In fact, the Company held over $1 billion in short-term debt in November and December 2022, as previously described. While the Company was able to secure a $1 billion term loan in July 2022 to meet the excessive short-term borrowing requirements, access to this type of facility at reasonable interest rates is not guaranteed in the future, particularly during times of extreme capital market volatility or the inability to access those markets as described earlier in my direct testimony. The dramatic increase in gas prices in 2022 and the resulting elevated short-term borrowing levels highlights the importance of maintaining sufficient short-term credit capacity to ensure that the Company is able to adequately fund gas purchases, continue operations, and serve customers.

Q. Consistent with previous rate cases, has the Company included the renewable liability balance in its projected short-term debt balance?

A. No. Consistent with the Company's RE Plan in Case No. U-21816 filed in November 2024, a renewable liability balance is not expected through the test year of this case. As described earlier in my direct testimony, the capital structure in general rate cases is composed of financing components used to fund its operations and capital investment and includes debt, equity, and deferred income tax balances. Since it would be inappropriate to include an asset balance, the Company has thus excluded this component from the projected capital structure.

Q. Please explain the deferred income tax adjustment of $526 million.

A. The Company's Tax Department has projected that the average deferred income tax balance for the test year ending October 31, 2026, will be $526 million higher than the December 31, 2023 balance. This increase is based on projecting book versus tax differences that the Company expects to record from January 2024 through October 2026. These adjustments total $526 million on a 13-month average basis for the test year. The development of the 13-month average deferred income tax balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 4.

Q. How was the ITC balance determined?

A. The Company's Tax Department has projected that the average ITC balance for the test year ending October 31, 2026 will be $115 million, $11 million lower than the December 2023 balance of $126 million. The balance is based on forecasted balances of both existing and anticipated new ITC credits that the Company expects to record from January 2024 through October 2026. These adjustments total $(11) million on a 13-month average basis for the test year.

Q. What balances did you use for ITC in the proposed capital structure?

A. I allocated the components for ITC based upon the allocation of long-term debt, preferred stock, and common equity in the recommended capital structure.

B. Development of Cost Rates

Q. Please explain the development of the total weighted cost of capital shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 19, column (g).

A. Column (d) represents the percentage of total capital provided by each of the components of the capital structure shown in column (a). These percentages were developed by dividing the amounts of capital shown in column (b) by the total ratemaking capitalization amount shown in line 19, column (b). Column (e) presents the costs, on a ratemaking basis, of each of the components in total ratemaking capitalization. Column (g) is the after-tax weighted cost of capital and is calculated by multiplying column (d) by column (e). The pre-tax weighted cost is shown in column (i) and is calculated by multiplying column (g) by the conversion factors in column (h).

i. Long-Term Debt Cost Rate

Q. What long-term debt annual cost rate did you use in this case?

A. I developed a 4.35% annual cost for long-term debt. The development of this annual cost rate is shown on Exhibit A-14 (MRB-4), Schedule D-2. Consistent with past Commission practice, the costs are determined on a net proceeds basis. I began with the debt issuances outstanding as of December 31, 2023. I then added the new debt issuances in January 2024 and August 2024. I then added the planned new debt issuances in May 2025, August 2025, May 2026, and August 2026. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, lines 44 through 47.

Q. Why did you use cost on a net proceeds basis?

A. Not reflecting costs on a net proceeds basis would understate costs. The net proceeds methodology accounts for underwriters' compensation and finance expenses. The fees and expenses are shown as a reduction in proceeds from the issuance of new securities, thereby increasing the cost of the issuance over the stated coupon rate.

Q. Please explain the cost rate you assumed for the planned debt issuances in May 2025, August 2025, May 2026, and August 2026.

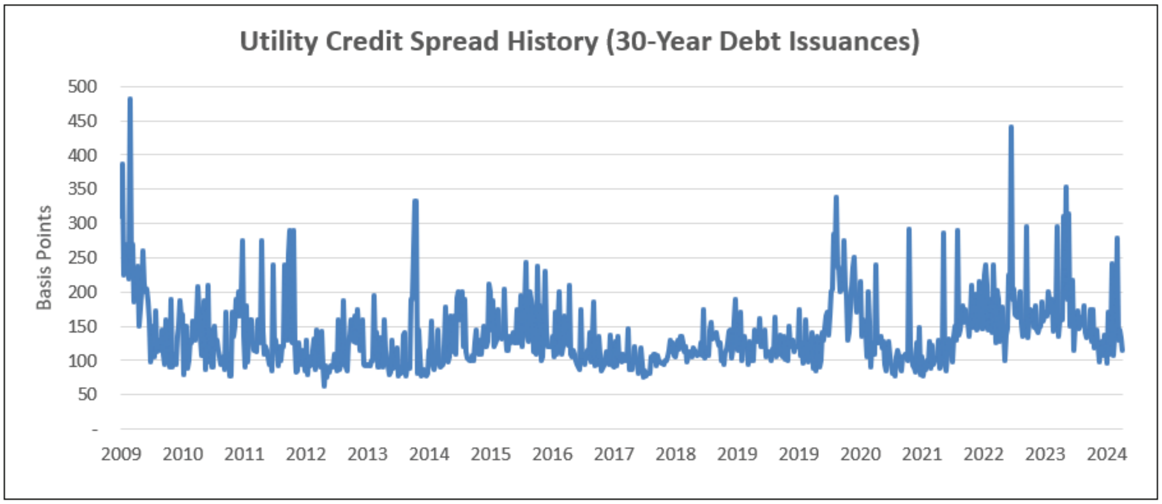
A. I assumed that all of the planned debt issuances will be 30-year bonds with a fixed coupon (interest) rate. To calculate the total interest rate (coupon) projection for these bonds, I started with the projected 30-year U.S. Treasury rate. For each of these planned debt issuances, I then added a 136 basis point credit spread. These interest rate calculations are shown on Exhibit A-14 (MRB-4), Schedule D-2.

Q. What is a credit spread?

A. A credit spread reflects the compensation investors receive for bearing credit risk of the investment in addition to the underlying Treasury rate. The total interest rate on a corporate bond is the summation of both the Treasury rate and the credit spread.

Q. How did you calculate the credit spread of 136 basis points?

A. Unlike U.S. Treasury rates, credit spreads for long-term bond issuances are not projected by financial forecasting companies. This is because spreads are very difficult to predict. Interest rate spreads are based on a number of factors, most notably the Company's credit rating and the market conditions at the time of the debt issuance, including both same-day and short-term supply/demand dynamics. In addition, credit spreads can be quite volatile in short periods of time. The volatility of credit spreads is illustrated on the following chart:



Given the lack of a reliable source for projected credit spreads, I applied the calculated average from the last 15 years. From 2009 to Mid-October 2024, the average credit spread on a 30-year debt issuance for investment grade utilities was approximately 136 basis points. This credit spread is very reasonable in relation to the historical spreads for 30-year debt issuances, as evidenced in the chart above.

Q. Are there any existing long-term debt issuances that have variable interest rates?

A. Yes. There are three debt issuances shown on Exhibit A-14 (MRB-4), Schedule D-2, which have variable interest rates. The Floating Rate First Mortgage Bonds ("FMB") issuances shown on line 27 and lines 30 through 31 have variable interest rates.

Q. What cost rates did you use for these variable rate issuances?

A. The interest rate for the Floating Rate FMB issuances is equal to SOFR less 30 basis points. Therefore, I took the projected three-month SOFR for the test year in this case (equal to 3.36%) and subtracted 30 basis points for an interest rate of 3.06%.

Q. Please explain Exhibit A-14 (MRB-4), Schedule D-2, line 58.

A. Exhibit A-14 (MRB-4), Schedule D-2, line 58, represents the amortization of losses on reacquired Consumers Energy debt (including call premium) for refinancings. This amortization needs to be added to the interest cost on the refinanced debt to determine Consumers Energy's true financing cost for the long-term debt. The Commission recognized recoverability of these costs in establishing the cost rate in Case No. U-16794.

Q. How did you calculate the amount shown on Exhibit A-14 (MRB-4), Schedule D-2, line 58?

A. The amount shown on line 58 represents the amortization of losses on reacquired debt with refunding (including call premiums). The projected amortization expense for the 12-month period ending October 2026 is $4,305,000.

ii. <u>Short-Term Debt Cost Rate</u>

Q. What short-term debt cost rate did you use in this case?

A. I used a short-term debt cost rate of 4.52%. This cost rate is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 5.

Q. Please explain the cost of short-term debt.

A. I projected a cost of short-term debt of $9.1 million. The development of this cost is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2. The cost of short-term debt – revolver has four components:

1. **<u>Interest on Borrowings</u>** – Equal to the projected outstanding balance times the projected interest rate. The projected balance, all assumed to be commercial paper, is $201.4 million, calculated on Exhibit A-14 (MRB-7), Schedule D-6. Commercial paper issuances are short term in nature, typically 1- to 90-day maturities. Interest charged on these short-term borrowings are based on several different factors, including market conditions, investor demand, and the tenor (number of days borrowed) of the issuance. I approximated the interest on commercial paper borrowings using the projected SOFR rate for the test year

of 3.36%. This was multiplied by the projected balance of $201.4 million. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $6.8 million for borrowings under the Commercial Paper Program;

2. **Letter of Credit Fees** – Equal to the projected Letters of Credit outstanding times a rate set forth by the facility the Letters of Credit are issued under. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for Letter of Credit Fees. The Letter of Credit Fees shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2, pertain to normal business Letters of Credit to cover ongoing items such as fuel purchases or margin support and also Letters of Credit to cover Midcontinent Independent System Operator, Inc. margin obligations;

3. **Unused (Commitment) Fees** – This cost consists of Annual Revolver Commitment Fees, which the Company is required to pay quarterly to the banks on the "unused" portion of the JPMorgan revolver and the Scotiabank revolver, and other required annual fees under the Revolving Credit agreements. The Revolver Commitment Fees are associated with maintaining fund availability. It should be noted that borrowings under the Company's Commercial Paper Program reduce the "availability" (or the amount the Company is able to draw) of the JPMorgan revolver but do not reduce the "unused" portion of the revolver in calculating the unused (commitment) fees. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.9 million for commitment fees; and

4. **Amortization/Expense of Facility Fees** – At the inception of a revolving credit facility, the borrower is required to pay upfront fees and issuance costs to the lenders. These issuance and upfront costs are amortized over the life of the revolver. For the Commercial Paper Program, there are annual fees required to maintain the facility. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $0.7 million for amortization of upfront revolver fees.

Q. Why is it important to allow for the recovery of commitment fees and amortization of facility fees in addition to the interest on short-term borrowings and interest on letters of credit?

A. These fees and costs are customary in revolving credit facilities and commercial paper agreements and are necessary to secure the financing and to keep the facilities available for the financing needs of the Company. The Company cannot avoid incurring these costs except by giving up the short-term borrowing facilities, which would not be a sound business decision. If these fees are not recovered through short-term debt cost, then they need to be recovered as part of long-term debt cost. The cost of short-term debt – short-term credit facilities represents the cost to provide $1.35 billion of necessary liquidity to Consumers Energy.

iii. Preferred Stock Cost Rate

Q. What is the annual cost of preferred stock?

A. The annual cost of preferred stock is shown on Exhibit A-14 (MRB-6), Schedule D-4. This cost is 4.50%.

iv. Common Equity Cost Rate

Q. What rate did you use for the cost of common equity?

A. Based on my recommended equity ratio of 50.75%, I applied a cost rate of 10.25% for common equity. As explained earlier in my testimony, to the extent that the Commission authorizes a lower equity ratio than that proposed by the Company, a higher ROE is necessary to prevent the potential for adverse credit impacts. The Company's capital structure and ROE recommendations in this case reflect the appropriate levels that the Commission should adopt with that principle in mind in order to preserve Consumers Energy's current credit rating.

v. Other Cost Rates

Q. What cost rates did you use for the remaining components of the capital structure?

A. Consistent with MPSC ratemaking practice, deferred income taxes are included at zero cost. The cost rates for each of the three components of ITC correspond to the cost rates for long-term debt, preferred stock, and common equity.

III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS, AND RECENT UTILITY BOND ISSUANCES

Q. Please describe Exhibit A-30 (MRB-8).

A. Exhibit A-30 (MRB-8) is included per the rate case filing requirements. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides current and historical credit ratings with associated outlooks for the previous five years for the utility and its parent company. Exhibit A-30 (MRB-8) shows Consumers Energy's and CMS Energy's current and historical credit ratings, along with associated credit outlooks, for the previous five years as published by S&P, Moody's, and Fitch Ratings. The credit ratings include senior secured debt, commercial paper, senior unsecured debt, preferred stock, junior subordinated debt, hybrid preferred securities ratings, and preferred stock ratings.

Q. Please describe Exhibit A-31 (MRB-9).

A. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides certain information related to bond issuances. Exhibit A-31 (MRB-9) shows recent public utility corporate bond issuances for a period of three months prior to and three months subsequent to, each of Consumers Energy's long-term public debt offerings issued during the 24 months prior to the date of the Application in this rate case. This summary includes the issue date, issuing company, type of offering (either secured or unsecured), amount of offering, coupon rate, S&P and Moody's credit ratings, maturity date, and spread on U.S. Treasury.

IV. PROJECTED CASH BALANCE

Q. Do you believe that the projected cash balance for the test year ending October 31, 2026, should be based on the 13 months ended June 30, 2024 (the working capital historical period)?

A. No. Using the 13 months ended June 2024 results in a cash balance of $7.3 million, which is lower than what is normally expected and required for the Company in the test year of this case.

Q. What do you believe that the projected cash balance for the test year ending October 31, 2026 should be based on?

A. I believe that the projected cash balance for the test year in this case should equate to approximately 1% of test year gas revenues, which results in a cash balance of $28.4 million. This is reflective of normal levels of cash balance.

Q. Has the Commission addressed the reasonableness of the Company's cash balance projection equal to approximately 1% of revenues?

A. Yes. In Case No. U-21389, the Administrative Law Judge ("ALJ") agreed with the Company that "the use of 1% of revenues as a benchmark for working capital cash is not arbitrary or inapplicable to determining the reasonableness of the amount of cash on hand." In its March 2024 Opinion in this case, the Commission found the ALJ's recommendation to be "well-reasoned and supported by the record."

V. SUMMARY AND CONCLUSIONS

Q. Please summarize your recommendations and conclusions.

A. Consumers Energy's capital structure should be based on the capital structure as of December 31, 2023, adjusted for the known and expected changes in long-term debt, common equity, short-term debt, deferred income taxes, and ITC, as shown on Exhibit A-14 (MRB-1), Schedule D-1. The cost rates developed are fair and reasonable and commensurate with the risks for the period of time rates are expected to be in effect. As shown on Exhibit A-14 (MRB-1), Schedule D-1, I recommend an overall after-tax rate of return of 6.22%. Also, the Company's projected cash balance for the test year in this case should be based on approximately 1% of test year gas revenues, which results in a balance of $28.4 million.

Q. Does this conclude your direct testimony?

A. Yes.

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 for other relief.	)))))	Case No. U-21806

DIRECT TESTIMONY

OF

ANN E. BULKLEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal at The Brattle Group ("Brattle"), a consulting firm that advises clients on regulatory finance and ratemaking issues.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this direct testimony before the Michigan Public Service Commission ("MPSC" or the "Commission") on behalf of Consumers Energy ("Consumers Energy" or the "Company").

Q. Please describe your background and professional experience in the energy and utility industries.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, and have more than 25 years of experience consulting to the energy industry. I have provided testimony regarding financial matters, including the cost of capital, before numerous regulatory agencies. I have advised energy and utility clients on a wide range of financial and economic issues, with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. A summary of my professional and educational background is presented in Attachment A to this testimony.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the return on equity ("ROE") for Consumers Energy's natural gas utility operations to be used for ratemaking purposes. I also address the reasonableness of the Company's proposed capital structure.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring:

Exhibit A-14 (AEB-1)	Schedule D-5	Cost of Common Shareholder's Equity.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

Q. Please provide a brief overview of the analyses that support your ROE recommendation.

A. I have estimated the market-based cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration the business and regulatory risk of the Company relative to the proxy group, and the Company's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to my ROE recommendation for these factors, I do consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

- Section III provides a summary of my analyses and conclusions.
- Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section V discusses current and projected capital market conditions and the effect of those conditions on the Company's cost of equity.
- Section VI explains my selection of the proxy group.
- Section VII describes my cost of equity analyses and the basis for my recommended ROE in this proceeding.
- Section VIII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case.
- Section IX presents my conclusions and recommendations.

III. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q. Please summarize the key factors that you consider in your analyses and upon which you base your recommended ROE.

A. My analyses and recommendations consider the following:

- The United States ("U.S.") Supreme Court's *Hope* and *Bluefield* decisions established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.[1]
- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in

[1] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope"); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield").

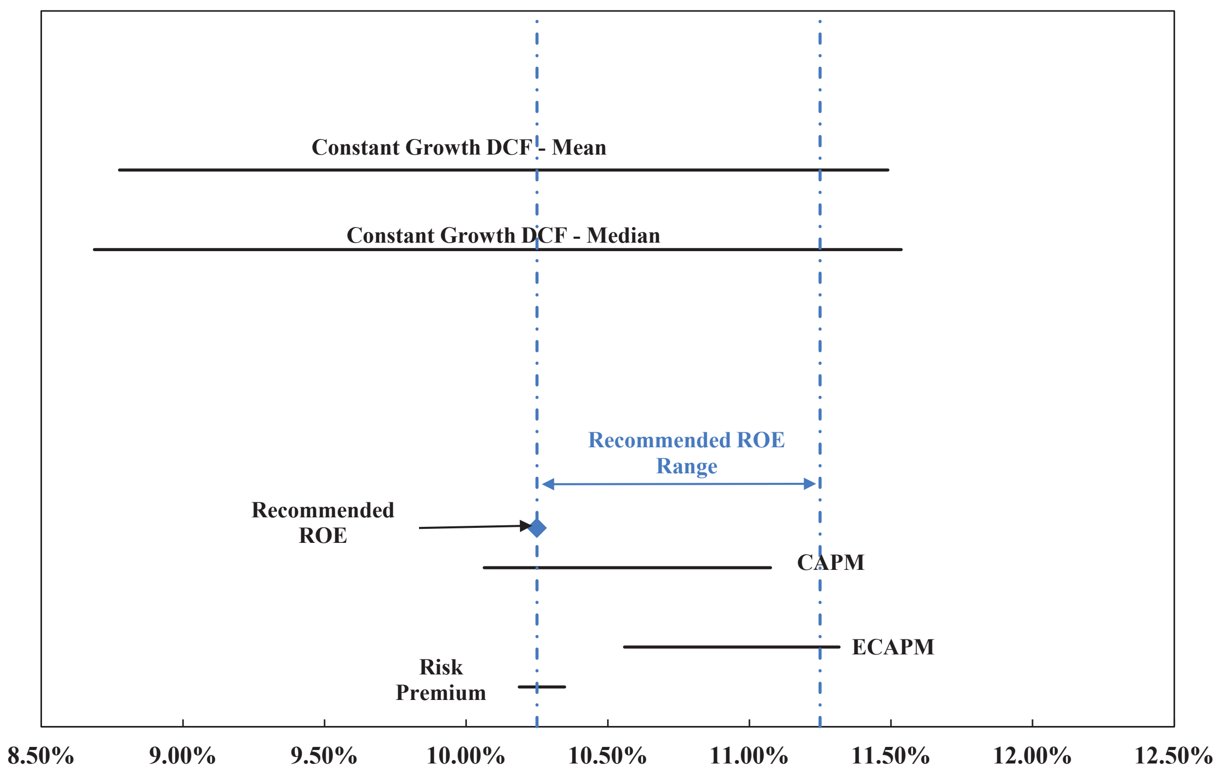
effect, these analyses rely on forward-looking inputs and assumptions (e.g. projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)

- Although the companies in my proxy group are generally comparable to Consumers Energy, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I consider the Company's regulatory, business, and financial risks relative to a proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q. What are the results of the models that you have used to estimate the market-based cost of equity for Consumers Energy?

A. Figure 1 summarizes the range of results produced by the cost of equity analyses.

Figure 1: Summary of Cost of Equity Analytical Results



As shown, the range of results across all methodologies is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies. As a result, my ROE recommendation considers the range of results of analyses, as well as the company-specific risk factors and current and prospective capital market conditions expected during the time when rates set in this case would be in effect.

Q. What is your recommended ROE for the Company in this proceeding?

A. Considering the analytical results of the market-based cost of equity models, current and prospective capital market conditions, and the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that an ROE in the range of 10.25% to 11.25% is reasonable, and within that range, the Company is requesting an ROE of 10.25%.

IV. <u>REGULATORY GUIDELINES</u>

Q. Please describe the principles that guide the establishment of the cost of capital for a regulated utility.

A. The U.S. Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates. [2]

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes. For example, in its decision in Case No. U-20963, the Commission stated that:

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[2] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

> The criteria for establishing a fair ROR for public utilities is rooted in the language of the landmark United States (U.S.) Supreme Court cases *Bluefield Waterworks & Improvement Co v Public Serv Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923), and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair ROR, consideration should be given to both investors and customers. As stated on page 12 of the December 23, 2008 order in U-15244 (December 23 order), "the rate of return should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise." Nevertheless, the Commission observes that the determination of what is fair or reasonable, "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." [Meridian Twp v City of East Lansing, 342 Mich 734, 749; 71 NW2d 234 (1955).[3]]

This guidance is in accordance with the *Hope* and *Bluefield* decisions and the principles that I have employed to estimate the cost of equity and recommend an ROE for the Company, including the principle that an allowed rate of return must be sufficient to enable regulated companies like Consumers Energy to attract capital on reasonable terms.

Q. Is fixing a fair rate of return just about protecting the utility's interests?

A. No. As the court noted in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[4] As the Court

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[3] MPSC Case No. U-20963, 12/22/2021 Order, at 221-222.

[4] *Bluefield*, 262 U.S. at 679, 693.

went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[5]

Q. Why is it important for a utility to have a reasonable opportunity to earn a return that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable gas service while maintaining its financial integrity. The authorized return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost, which ultimately has a negative effect on customers.

Q. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities nationally. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk within that jurisdiction generally, and for that utility particularly. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative

[5] *Hope*, 320 U.S. at 591, 603.

investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

Q. What is the standard for setting the ROE in any jurisdiction?

A. The stand-alone ratemaking principle is a foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. Consistent with this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for Consumers Energy's natural gas utility operations in Michigan.

Q. Does the fact that Consumers Energy is a wholly owned subsidiary of CMS Energy Corporation ("CMS"), a publicly traded company, affect your analysis?

A. No. In this proceeding, consistent with stand-alone ratemaking principles, it is appropriate to establish the cost of equity for Consumers Energy's natural gas operations, not its publicly-traded parent, CMS. More importantly, however, it is appropriate to establish a cost of equity and capital structure that provide the ability to attract capital on reasonable terms for Consumers Energy's natural gas operations, both on a stand-alone basis and within CMS. While Consumers Energy is committed to investing the required capital to provide safe and reliable natural gas service, because it is a subsidiary of CMS, the Company competes with the other CMS subsidiaries for discretionary investment capital. In determining how to allocate its finite discretionary capital resources, it would be reasonable for CMS to consider the authorized ROE of each of its subsidiaries.

Q. Are the regulatory framework, the authorized ROE, and equity ratio important to the financial community?

A. Yes. The regulatory framework is one of the most important factors in investors' assessments of risk. Specifically, the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for reinforcing a utility's creditworthiness and financial stability in the jurisdiction. To the extent authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, such actions are considered by both debt and equity investors in the overall risk assessment of the regulatory jurisdiction in which the company operates. The direct testimony of Company witness Marc R. Bleckman describes in further detail the effect of the authorized ROE and equity ratio on credit quality as well as rating agencies' assessment of Michigan's regulatory environment.

Q. What are your conclusions regarding regulatory guidelines?

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn an ROE that is adequate to attract capital at reasonable terms and sufficient to ensure its financial integrity. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

V. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. The models used to estimate the cost of equity rely on market data and thus the results of those models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analysis uses current and projected market data, including stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE, and the ROE to be used for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is important to consider projected market data to estimate the return for that forward-looking period.

Q. Do changes in capital market conditions since the Company's last rate proceeding indicate an elevated cost of equity?

A. Yes. Core inflation and long-term bond yields compared to the Company's last rate proceeding demonstrates an elevated cost of equity. As shown in Figure 2, short-term and long-term interest rates as well as core inflation have remained high since the Commission adopted the settlement which includes an ROE of 9.90% in the Company's last gas rate case filed in 2023. While inflation has declined from its peak in 2022, it still remains above the level of the Federal Reserve's target of 2%.

Figure 2: Change in Market Conditions Since Company's Last Rate Case[6]

Docket	Date	Federal Funds Rate	30-Day Avg 30 Year Treasury Bond Yield	Core Inflation Rate	Authorized ROE
Docket No. U-21490 (Direct Filing)	2023-11-17	5.33%	4.86%	4.02%	9.90%
Docket No. U-21490 (Rebuttal Filing)	2024-04-26	5.33%	4.57%	3.21%	9.90%
Current	2024-10-31	4.83%	4.30%	3.26%	
Change since Direct		-0.50%	-0.56%	-0.76%	
Change since Rebuttal		-0.50%	-0.28%	0.05%	

Q. What has the level of inflation been over the past few years?

A. As shown in Figure 3, core inflation increased steadily beginning in early 2021, rising from 1.40% in January 2021 to a high of 6.64% in September 2022, which was the largest 12-month increase since 1982.[7] Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain significantly above the Federal Reserve's target level of 2.0%.

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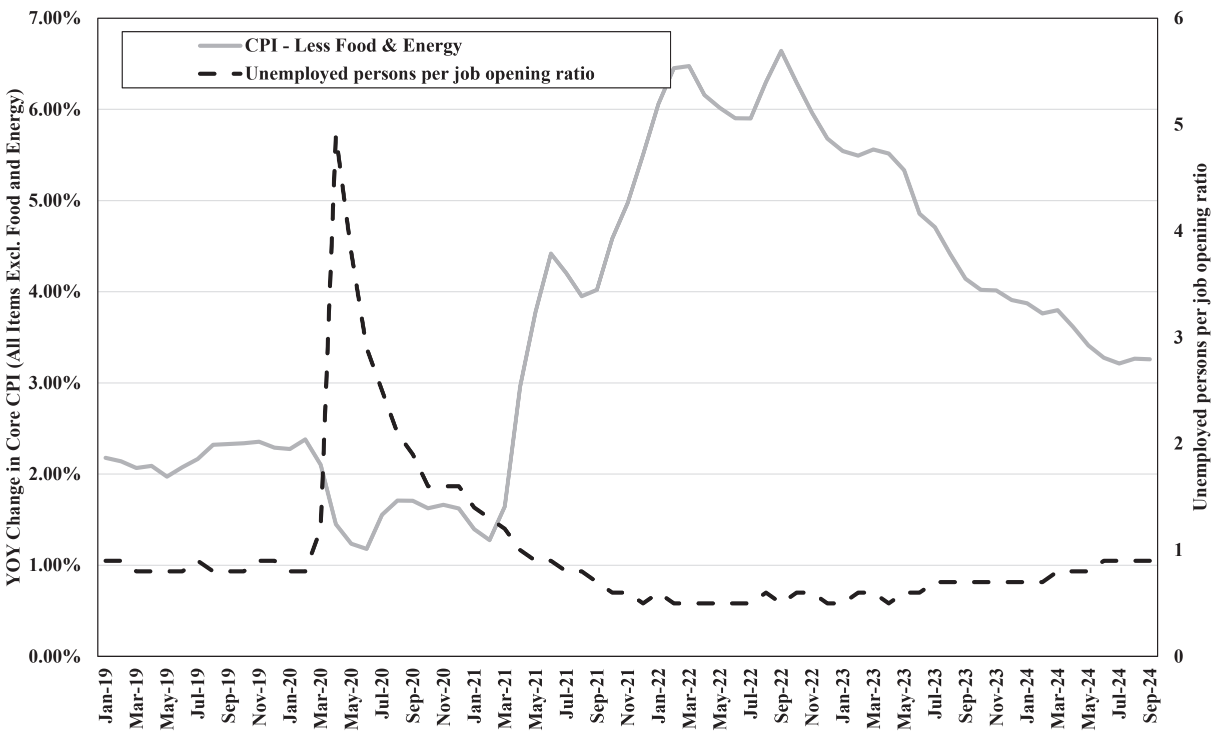
6 St. Louis Federal Reserve Bank; Bureau of Labor Statistics. While the prior rate case direct testimony and rebuttal testimony were filed on December 15, 2023 and May 17, 2024, respectively, the analysis used to support the recommendation for the Company's ROE relied on data from November 17, 2023 and April 26, 2024, respectively.

7 *Bloomberg,* Pickert, Reade, "Core US Inflation Rises to 40-Year High, Securing Big Fed Hike", October 13, 2022.

Figure 3 presents the year-over-year change in core inflation, as measured by the Consumer Price Index excluding food and energy prices as published by the Bureau of Labor Statistics. I considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve because it removes the effect of food and energy prices, which can be highly volatile.

In addition, I also considered the ratio of unemployed persons per job opening, which was 0.9 in September 2024 (the most recent data available at the time of writing) and has been consistently below 1.0 since April 2021, despite the Federal Reserve's accelerated policy normalization. This indicates sustained strength in the labor market. Given the Federal Reserve's dual mandate of maximum employment and price stability, the strength in the labor market allowed the federal reserve to focus on the priority of reducing inflation and pursue the restrictive monetary policy needed to reduce inflation.

Figure 3: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to September 2024[8]



[8] Bureau of Labor Statistics.

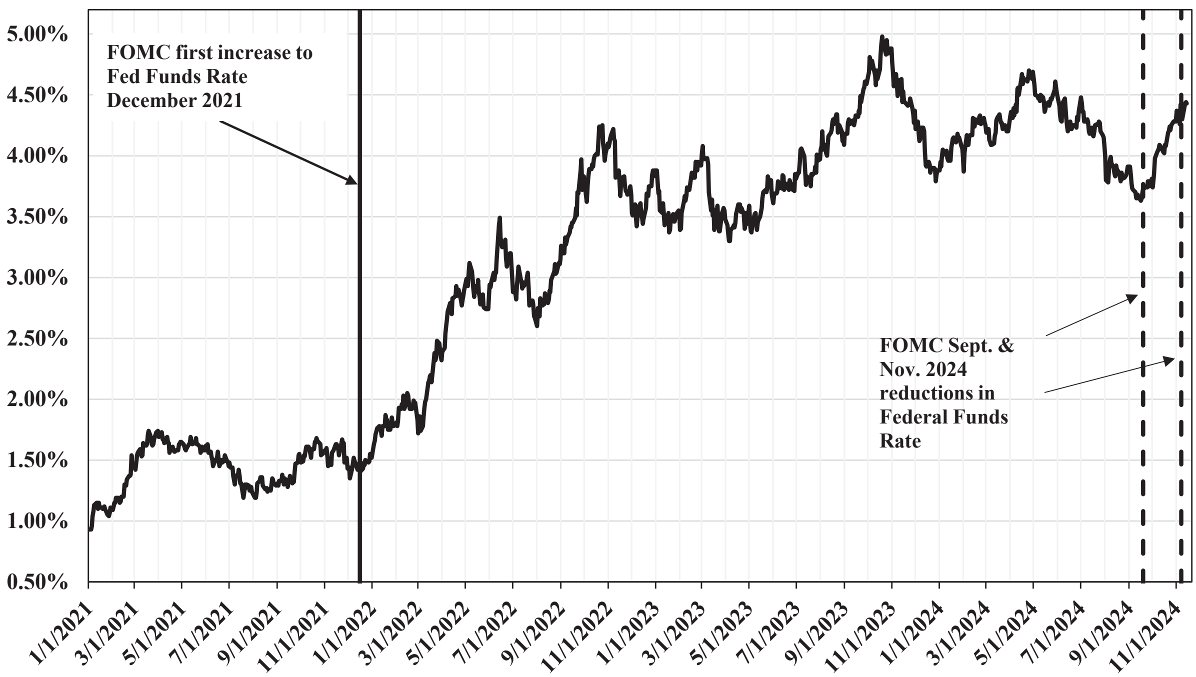
Q. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A. The dramatic increase in inflation prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Between the March 2022 Federal Open Market Committee ("FOMC") meeting and the July 2023 FOMC meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00% to 0.25% to a range of 5.25% to 5.50%. As discussed below, in light of the progress on reducing inflation and the balancing of the dual mandate, the Federal Reserve lowered the federal funds rate in September and November 2024 by a total of 75 basis points to a range of 4.50% to 4.75%.

Q. How have yields on long-term government bonds responded to the Federal Reserve's use of monetary policy?

A. As shown in Figure 4, beginning in December 2021, as the Federal Reserve substantially increased the federal funds rate in response to persistent increased levels of inflation, longer-term interest rates increased. Since the Federal Reserve's December 2021 meeting, when the first increase to the federal funds rate occurred, the yield on 10-year Treasury bonds has increased substantially from 1.47% to a peak of 4.95% in October 2023, remaining well above 2021 levels throughout 2024. It is important to note that while the FOMC has reduced the Federal Funds Rate twice in recent months, the yield on the 30-year Treasury bond responded only briefly, on the expectation of the first rate cut in September 2024, but has risen steadily since that time. As of November 14, which was a week following the second reduction to the Federal Funds Rate, the yield on the 30-year Treasury bond was 4.43%, which is substantially higher than the yield just prior to the actions of the FOMC in September 2024.

Figure 4: 10-Year Treasury Bond Yield, Janaury 2021 through September 30, 2024[9]



Q. What is the expected path of monetary policy over the near-term?

A. While the Federal Reserve cut the interest rate by 50 basis points in September 2024 and 25 basis points in November 2024, Chairman Powell has repeatedly noted that the FOMC is "not on any preset course" and will "continue to make our decisions meeting to meeting."[10] Most recently, on November 14, 2024, Chairman Powell noted that there was no rush to lower interest rates, noting a solid job market, ongoing economic growth, and inflation that remains above its 2% target. Responding to questions regarding the effect of higher tariffs and changes in immigration policy on economic growth and inflation,

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9 S&P Capital IQ Pro.

10 *Id.*

Chairman Powell noted that the answer is not obvious until we see the actual policies; however, he noted that "The economy is not sending any signals that we need to be in a hurry to lower rates. The strength we are currently seeing in the economy gives us the ability to approach our decisions carefully."[11]

In addition to the changes expected with short-term interest rates, economists have also shifted their targets for long-term government bond yields with *Reuters* noting that BofA Global Research increased their near-term target for long-term government bond yields from a range of 3.5% to 4.25% to a range of 4.25% to 4.75%.[12]

Q. What are expectations for the yields on long-term government bonds?

A. Economists consider the expected policy of the Federal Reserve in the development of their forecasts of long-term government bond yields and, prior to the FOMC's decision to reduce the federal funds rate at the September 2024 meeting, had projected a decrease in the federal funds rate. For example, *Blue Chip Financial Forecasts* provides a forecast of both the federal funds rate and the yield on the 30-year Treasury bond. In the most recent published *Blue Chip Financial Forecasts* report, economists projected the federal funds rate to decline from 4.6% in Q4/2024 to 3.3% in Q1/2026.[13] However, economists' consensus estimate of the yield on the 30-year Treasury bond is expected to remain relatively stable over the same time-period. The yield on the 30-year Treasury bond as reported by *Blue Chip Financial Forecasts* is expected to range from 4.1% in Q4/2024 to 4.0% in Q1/2026.[14] Therefore, economists, who consider the expected policy of the

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[11] Ann Saphir and Howard Schneider, "Powell says no need for Fed to rush rate cuts given strong economy," *Reuters*, November 14, 2024.

[12] *Id*.

[13] *Blue Chip Financial Forecasts*, Vol. 43, No. 10, October 1, 2024, at 2.

[14] *Id.*

Federal Reserve, expect the yield on the 30-year Treasury bond to remain elevated over the near-term.

Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A. Due to their effect on the estimated cost of equity, it is important that current and projected market conditions be considered in setting the forward-looking ROE in this proceeding. As shown in Figure 2, long-term interest rates remain elevated when compared to the Company's last rate proceeding. Further, while the FOMC decreased the federal funds rate, there is uncertainty regarding the policies of the new administration with respect to tariffs and immigration, which are projected to be inflationary. Recently, bond yields have been resistant to declines in the federal funds rate, and yields are generally consistent with the conditions that existed at the time of the Company's last rate proceeding.

VI. PROXY GROUP SELECTION

Q. Please provide a brief profile of Consumers Energy's natural gas utility operations.

A. Consumers Energy's natural gas operations include gas transmission, storage, and distribution system and is a wholly owned subsidiary of CMS Energy Corporation. The Company provides natural gas service to approximately 1.8 million customers in Michigan with approximately $2.2 billion in operating revenues from natural gas sales.[15] As of December 31, 2023, the Company's net utility natural gas plant was approximately

[15] Consumers Energy Company, Annual Report of Natural Gas Utilities to the Michigan Public Service Commission, December 31, 2023, at pages 300-301.

$9.7 billion.[16] Consumers Energy currently has an investment-grade long-term rating of A- (Outlook: Stable) from S&P and A3 (Outlook: Stable) from Moody's.[17]

Q. Why have you used a group of proxy companies to estimate the cost of equity for Consumers Energy?

A. In this proceeding, the cost of equity is being estimated for a natural gas utility that is not itself publicly traded. Because the cost of equity is a market-based concept and the Company's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.

Even if the Company was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to estimate the appropriate cost of equity for the Company.

Q. How did you select the companies included in your proxy group?

A. I began with the group of nine companies that *Value Line* classifies as Natural Gas Distribution Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because this is a requirement for the constant growth DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;

[16] Exhibit A-2 (HLR-8), Schedule B-6, page 1.
[17] S&P Global Market Intelligence, accessed October 29, 2024. Moody's as of April 27, 2023.

- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- derive more than 70.00% of their total operating income from regulated operations;
- derive more than 60.00% of regulated operating income from gas distribution operations; and
- were not parties to a merger or transformative transaction during the analytical periods relied on.

Q. What is the composition of your proxy group?

A. The screening criteria discussed above is shown in Exhibit A-14 (AEB-1), Schedule D-5, page 2, and results in a proxy group consisting of the companies shown in Figure 5.

Figure 5: Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
NiSource Inc.	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Southwest Gas Corporation	SWX
Spire, Inc.	SR

VII. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of a regulated utility.

A. The rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (i.e. book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the rate of return. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data when establishing the ROE.

Q. How is the required cost of equity determined?

A. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q. What methods did you use to estimate the cost of equity for the Company in this proceeding?

A. I consider the results of the constant growth form of the DCF model, the CAPM, the ECAPM, and a BYRP analysis. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q. Is it important to use more than one analytical approach?

A. Yes. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[18] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[19] recommend the CAPM, DCF, and BYRP approaches.

Further, each model relies on different assumptions, certain of which better reflect current and projected market conditions at different times. For example, the CAPM and ECAPM analyses rely directly on interest rates as an assumption in the models and therefore may more directly reflect the market conditions expected when the Company's rates are in effect. Accordingly, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

A. <u>Constant Growth DCF Model</u>

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required cost of equity. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

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18 Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies* (3rd ed. 2000), at 214.

19 Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice* (7th ed. 1994), at 341.

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the constant growth DCF model?

A. The constant growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data did you use to calculate the dividend yield in your constant growth DCF model?

A. The dividend yield in my constant growth DCF model is based on the proxy companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days as of September 30, 2024.

Q. Why did you use three averaging periods for stock prices?

A. In my constant growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the cost of equity is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long term.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming 12-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its constant growth form, the DCF model (i.e. Equation [2] shown previously) assumes a single long-term growth rate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume that the dividend payout ratio remains constant and that earnings per share ("EPS"), dividends per share, and book value per share all grow at the same constant rate. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. Therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects. Accordingly, I have incorporated a number of sources of long-term EPS growth rates into the constant growth DCF model.

Q. What sources of long-term growth rates did you rely on in your constant growth DCF model?

A. My constant growth DCF model incorporates three sources of long-term projected EPS growth rates: (1) *Zacks Investment Research* (*Zacks*); (2) Yahoo! Finance; and (3) *Value Line*.

Q. How do you calculate the range of results for the constant growth DCF models?

A. I calculate the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (i.e. the lowest of the *Zacks*, Yahoo! Finance, and *Value Line* projected EPS growth rates) for each of the proxy group companies. I use a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculate results using the average EPS growth rate from all three sources for each proxy group company.

Q. Please summarize the results of your constant growth DCF analyses.

A. Exhibit A-14 (AEB-1), Schedule D-5, pages 3 through 5, and Figure 6 summarize the results of the constant growth DCF models.

Figure 6: Summary of Constant Growth DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	8.59%	9.87%	11.30%
90-Day Avg. Stock Price	8.79%	10.06%	11.50%
180-Day Avg. Stock Price	8.95%	10.23%	11.66%
Average	8.78%	10.05%	11.49%
Median Results:			
30-Day Avg. Stock Price	8.48%	9.83%	11.33%
90-Day Avg. Stock Price	8.72%	10.05%	11.57%
180-Day Avg. Stock Price	8.86%	10.17%	11.71%
Average	8.69%	10.02%	11.54%

Q. Have regulatory commissions acknowledged the reasonableness of considering multiple models to estimate the cost of equity given the current capital market conditions?

A. Yes. For example, in its May 2022 decision establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission concluded that, based on high inflation and increased interest rates, weight should be placed on risk premium models, such as the CAPM, in addition to the DCF, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed

> judgement based on I&E's DCF and CAPM methodologies.[20]
>
> ***
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[21]

B. CAPM Analysis

Q. Please briefly describe the Capital Asset Pricing Model.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security.[22] This second component is the product of the market risk premium and the beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

[20] Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, at 154-155.

[21] *Id*., at 177-178.

[22] Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market ROE;

β = the beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In this specification, the term ($r_m - r_f$) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined as:

$$\beta = \frac{Covariance\ (r_e, r_m)}{Variance\ (r_m)} \quad [4]$$

Variance (r_m) represents the variance of the market return, which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analyses?

A. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds, which is 4.07%;[23] (2) the average projected 30-year U.S. Treasury bond yield for the first quarter of 2025 through the first quarter of 2026,

[23] S&P IQ Pro, as of September 30, 2024.

which is 4.02%;[24] and (3) the average projected 30-year U.S. Treasury bond yield for 2026 through 2030, which is 4.30%.[25]

Q. What beta coefficients did you use in your CAPM analysis?

A. As shown in Exhibit A-14 (AEB-1), Schedule D-5, pages 6 through 11, I use the beta coefficients for the proxy group companies as reported by *Bloomberg* and *Value Line*. The beta coefficients reported by *Bloomberg* are calculated using 10 years of weekly returns relative to the S&P 500 Index. The beta coefficients reported by *Value Line* are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown in Exhibit A-14 (AEB-1), Schedule D-5, pages 12 through 14, I also considered an additional CAPM analysis that relies on the long-term average utility beta coefficient for the companies in my proxy group from 2013 through 2023, which are presented in Exhibit A-14 (AEB-1), Schedule D-5, page 15.

Q. How do you estimate the market risk premium in the CAPM?

A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit A-14 (AEB-1), Schedule D-5, pages 16 through 21, the expected market return is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.52% and a weighted long-term growth rate of 10.45%, the estimated required market return for the S&P 500 Index as of September 30, 2024 is 12.04%.

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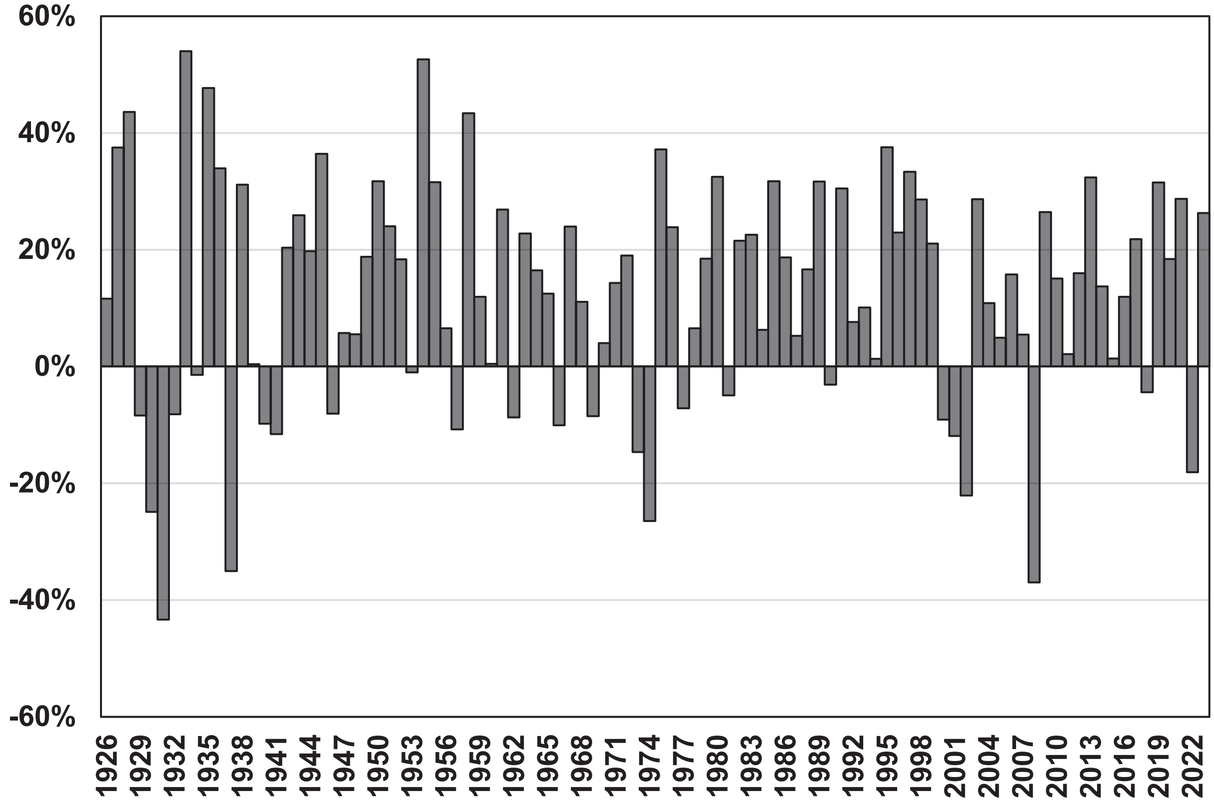
[24] *Blue Chip Financial Forecasts*, Vol. 43, No. 10, October 1, 2024, at 2.

[25] *Blue Chip Financial Forecasts*, Vol. 43, No. 6, May 31, 2024, at 14.

Q. How does the expected market return compare to observed historical market returns?

A. As show in Figure 7, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.04% is reasonable. In 52 out of the past 98 years (or approximately 53% of observations), the realized equity market return was at least 12.04% or greater.

Figure 7: Realized U.S. Equity Market Returns (1926–2023)[26]



Q. Did you consider another form of the CAPM in your analysis?

A. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for the Company.[27] The ECAPM calculates the product of the adjusted beta coefficient and

[26] Depicts total annual returns on large company stocks, as reported in the 2022 *Kroll* SBBI Yearbook for 1926-2022 and from S&P Capital IQ Professional for 2023.

[27] See, e.g., Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., June 1, 2006, at 189.

the market risk premium and applies a weight of 75.00% to that result. The model then applies a 25.00% weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e = the required market ROE;

β = adjusted beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, meaning that the CAPM underestimates the cost of equity for companies with a beta less than 1.0 and overestimates the cost of equity for companies with a beta greater than 1.0.[28]

Consistent with my CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the current *Bloomberg*, current *Value Line*, and long-term *Value Line* beta coefficients.

[28] *Id.,* at 191.

Q. What are the results of your CAPM and ECAPM analyses?

A. The results of my CAPM and ECAPM analyses are summarized in Figure 8, as well as presented in Exhibit A-14 (AEB-1), Schedule D-5, pages 6 through 14.

Figure 8: CAPM and ECAPM Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.05%	11.04%	11.07%
Current Bloomberg Beta	10.15%	10.13%	10.20%
Long-term Avg. *Value Line* Beta	10.08%	10.06%	10.13%
ECAPM:			
Current *Value Line* Beta	11.30%	11.29%	11.32%
Current Bloomberg Beta	10.62%	10.61%	10.66%
Long-term Avg. *Value Line* Beta	10.57%	10.56%	10.61%

C. BYRP Analysis

Q. Please describe your BYRP analysis.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for natural gas utilities as the historical measure of the cost of equity to determine the risk premium.

Q. What is the fundamental relationship between the equity risk premium and interest rates?

A. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (i.e. as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis presented in Exhibit A-14 (AEB-1), Schedule D-5, pages 22 through 25, establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the long-term Treasury bond yield is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[29]

Q. Is the BYRP analysis relevant to investors?

A. Yes. Investors are aware of authorized ROEs in other jurisdictions and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my BYRP analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

[29] See, e.g., S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93*," Managerial and Decision Economics*, Vol. 19, No. 2, March 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). See also, Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

Q. What did your BYRP analysis reveal?

A. As shown in Figure 9, from January 1980 through September 2024, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$\mathrm{RP} = \mathrm{a} + \mathrm{b}(\mathrm{T}) \qquad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds);

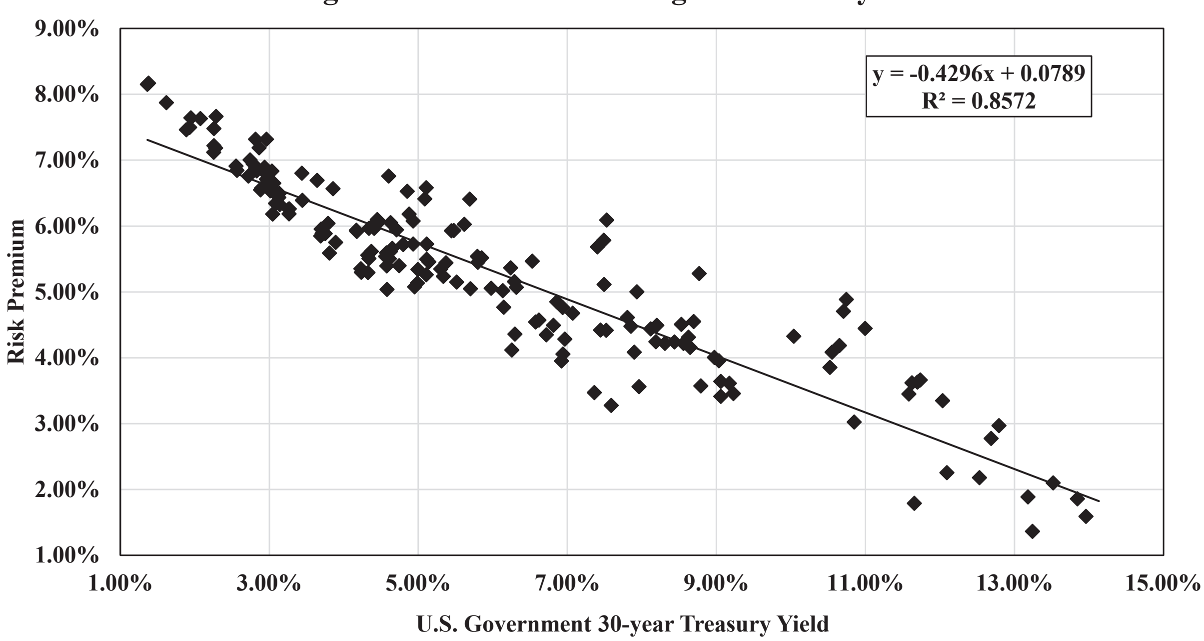
a = intercept term;

b = slope term; and

T = 30-year U.S. Treasury bond yield.

Data regarding authorized ROEs were derived from the natural gas utility rate cases over this period as reported by Regulatory Research Associates ("RRA").[30] The equation's coefficients are statistically significant at the 99.00% level.

Figure 9: Risk Premium Regression Analysis



[30] The data was screened to eliminate limited issue rider cases, transmission cases, and cases that were silent with respect to the authorized ROE.

Q. What are the results of your BYRP analysis?

A. Figure 10 presents the results of my BYRP analysis, which is also presented in more detail in Exhibit A-14, (AEB-1), Schedule D-5, page 22.

Figure 10: BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
Bond Yield Risk Premium	10.22%	10.19%	10.35%

Q. How did the results of the BYRP inform your recommended ROE for Consumers Energy?

A. I have considered the results of the BYRP analysis in setting my recommended ROE for Consumers Energy. As noted above, investors consider the ROE determination by a regulator when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The BYRP analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of natural gas utilities across the U.S.

VIII. <u>REGULATORY AND BUSINESS RISKS</u>

Q. Do the results of the cost of equity analyses alone provide an appropriate estimate of the cost of equity for the Company?

A. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. Several additional factors must be considered when determining where the Company's cost of equity falls within the range of analytical results. These risk factors, discussed below, should be considered with respect to their overall effect on the Company's risk profile relative to the proxy group.

A. Flotation Cost

Q. What are flotation costs?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

Q. Why is it important to consider flotation costs in the allowed ROE?

A. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.

Q. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of a utility's flotation cost is incurred prior to the test year but remains part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs during the test year or is planned for the test year because failure to allow recovery of past flotation costs may deny Consumers Energy the opportunity to earn its required rate of return in the future.

Q. Can you provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested?

A. Yes. Suppose CMS issues stock with a value of $100, and an equity investor invests $100 in CMS in exchange for that stock. Further suppose that, after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, CMS ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. CMS invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though she contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed. This is consistent with basic ratemaking principles.

Q. Is the date of CMS's last issued common equity important in the determination of flotation costs?

A. No. As shown in Exhibit A-14 (AEB-1), Schedule D-5, page 26, CMS closed on equity issuances of approximately $298 million and $282 million (for a total of 55.78 million shares of common stock) in October 2004 and March 2005, respectively. The vintage of the issuance, however, is not particularly important because the investor suffers a shortfall in every year that she should have a reasonable opportunity to earn a return on the full amount of capital that she has contributed. Returning to my earlier example, the investor who contributed $100 is entitled to a reasonable opportunity to earn a return on $100 not only in the first year after the investment, but in every subsequent year in which she has the $100 invested. Leaving aside depreciation, which is dealt with separately, there is no basis to conclude that the investor is entitled to earn a return on $100 in the first year after issuance, but thereafter is entitled to earn a return on only $97. As long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q. Is the need to consider flotation costs eliminated because Consumers Energy is a wholly-owned subsidiary of CMS?

A. No. Although Consumers Energy is a wholly-owned subsidiary of CMS, it is appropriate to consider flotation costs because wholly-owned subsidiaries receive equity capital from their parent and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based upon the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately penalizes the investors that fund the utility operations and could inhibit the utility's ability to obtain new equity capital at a reasonable cost.

Q. Is the need to consider flotation costs recognized by the academic and financial communities?

A. Yes. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair rate of return. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this

> reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[31]

Q. How did you calculate the flotation costs for CMS?

A. My flotation cost calculation is based on the costs of issuing equity that were incurred by CMS in its two most recent common equity issuances. That flotation cost percentage is then applied to the proxy group in the DCF analysis to estimate the impact on the cost of equity associated with flotation costs. As shown in Exhibit A-14 (AEB-1), Schedule D-5, page 26, based on the flotation costs previously incurred by CMS, the average impact on the proxy group's cost of equity is 14 basis points (i.e. 0.14%).

Q. Do your final cost of equity results include an adjustment for flotation cost recovery?

A. No. While the final ROE results do not incorporate an explicit adjustment for flotation costs, I have considered the effect of flotation costs, along with the other risk factors present for the Company, in determining where, within the range of analytical results, my recommended ROE for the Company should fall.

B. <u>Capital Expenditures</u>

Q. What are the Company's projected capital expenditure requirements over the next few years?

A. As of December 31, 2023, the Company had net gas utility plant of approximately $9.72 billion,[32] and the Company currently projects capital expenditures for 2025 through

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[31] Shannon P. Pratt, *Cost of Capital Estimation and Applications* (2nd ed. 2002), at 220-221.

[32] Exhibit A-2 (HLR-8), Schedule B-6, page 1.

2029 of approximately $6.00 billion,[33] which represent approximately 62% of its current net utility plant.

Q. How do Consumers Energy's capital expenditure requirements compare to those of the proxy group companies?

A. As shown Exhibit A-14 (AEB-1), Schedule D-5, page 27, I have calculated the ratio of expected capital expenditures to net utility plant for Consumers Energy and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2025 through 2029 by its total net utility plant as of December 31, 2023. As shown, Consumers Energy's ratio of capital expenditures as a percentage of net utility plant is lower than the median for the proxy group companies, however the capital expenditures still represent an extensive capital project relative to the total net plant utility.

Q. How is the Company's risk profile affected by their substantial capital expenditure requirements?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with significant capital expenditures?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and,

[33] Exhibit A-42 (NPD-1), page 86.

therefore, credit ratings. To that point, S&P explains the importance of regulatory support for a significant amount of capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[34]

Recently, S&P evaluated the capital expenditure trends in the utility sector, noting that the balance between operating with negative discretionary cash flow from operations offset by reliable access to capital markets for financing may be tested through ever-increasing capital expenditure requirements as a result of the transformation of the energy sector through the focus on low/no carbon generation, electrification, and the replacement of aging infrastructure:

> Some companies have been unable to support financial metrics consistent with former ratings as their discretionary cash flow deteriorated. This trend was a significant contributor to the sector seeing the median rating decline to 'BBB+' from 'A-' for the first time in 2022. What is less clear is whether or not management teams will take steps to forestall another step down in credit quality as high capital outlays persist. So far in 2023, we have not seen evidence that equity issuance is keeping pace with debt issuance to fill

[34] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

> ever-deepening discretionary cash flow shortfalls, but time will tell.
>
> ***
>
> Despite the improvement in the economic outlook, we expect inflation, high interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. We are cautious about the durability of the current stable ratings outlook given persistently high capital spending that now supports a trend of deterioration in discretionary cash flow. Without a commensurate focus on balance sheet preservation through equity support of discretionary cash flow deficits, limited financial cushions could give rise to another round of negative rating actions. The question then comes back to management priorities and financial policy decisions, or utilities may be faced with another step down in the median ratings. [35]

Therefore, to the extent that Consumers Energy's rates do not permit the opportunity to recover its capital investments on a regular and timely basis, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q. Does the Company currently have a capital tracking mechanism to recover the costs associated with its gas capital expenditures plan between rate cases?

A. No. Consumers Energy currently has not requested approval to recover gas capital investment costs between rate cases utilizing a capital tracking mechanism. Therefore, Consumers Energy depends entirely on rate case filings for gas capital cost recovery. However, significant capital programs like Consumers Energy's generally receive cost recovery through infrastructure and capital trackers. As shown in Exhibit A-14 (AEB-1),

35 S&P Global Ratings, "Record CapEx Fuels Growth Along With Credit Risk For North American Investor-Owned Utilities," September 12, 2023, at 5, 7-8.

Schedule D-5, page 29, approximately 71% of the companies in the proxy group currently have mechanisms for some form of capital cost recovery in place.

Q. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A. Even though Consumers Energy has lower projected capital expenditure programs relative to net utility plant of the proxy group over the next five years, the Company still has a significant capital spend program. Further, unlike a number of the operating subsidiaries of the proxy group, Consumers Energy does not currently have a capital tracking mechanism for gas capital investment. This results in greater risk for the Company than the proxy group, all else being equal.

C. <u>Regulatory Risk</u>

Q. How does the regulatory environment affect investors' risk assessments?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, their decisions should enable the utility to attract capital at reasonable terms, and that doing so balances the long-term interests of investors and customers. Utilities must finance their operations and thus require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. The Company is no exception. Therefore, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, a utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (i.e. the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. Do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Yes. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00%. Therefore, Moody's assigns regulatory risk a 50.00% weighting in the overall assessment of business and financial risk for regulated utilities.[36]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "we assess regulatory advantage because the influence of the regulatory framework and regime is of critical importance. It defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[37] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[38]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[u]tility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the regulatory framework is a key determinant of the credit quality of a utility."[39] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[t]he regulatory framework is important because it provides the basis for decisions that affect utilities,

[36] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 2.
[37] Standard & Poor's Global Ratings, "Sector-Specific Corporate Methodology," April 4, 2024, at 147.
[38] *Id.*
[39] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 8.

including rate-setting as well as the consistency and predictability of regulatory decision-making."[40]

Q. Have you conducted an analysis to compare the cost recovery mechanisms of Consumers Energy to the cost recovery mechanisms approved in the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Michigan based on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (i.e. forecast vs. historical); (2) use of rate design or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence of capital cost recovery between rate cases. Each are described below and are summarized in Exhibit A-14 (AEB-1), Schedule D-5, page 29.

> <u>Test Year Convention:</u> Consumers Energy uses a forecasted test year, and similarly, half of the utility operating subsidiaries of the companies in the proxy group also use either a fully forecasted or partially forecasted test year. Forecast test years have been relied on for several years and produce cost estimates that are more reflective of future costs, which results in more accurate recovery of incurred costs and mitigates the regulatory lag associated with historical test years. As Lowry, Hovde, Getachew, and Makos explain in their 2010 report, *Forward Test Years for US Electric Utilities*:
>
> > This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future.[41]

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[40] *Id*.

[41] M.N. Lowry, D. Hovde, L. Getachew, and M. Makos, Forward Test Years for US Electric Utilities, prepared for Edison Electric Institute, August 2010, at 1.

Volumetric Risk: Consumers Energy does not currently have protection against volumetric risk because the Company requested not to continue its revenue decoupling mechanism in the Company's last rate proceeding.[42] Approximately 92% of the utility operating subsidiaries of the proxy group companies have some form of revenue stabilization through either decoupling, formula-based rates, and/or straight-fixed variable rate design that allow them to break the link between customer usage and revenues.

Capital Cost Recovery: As previously mentioned, Consumers Energy does not have a capital tracking mechanism to recover gas capital investment costs between rate cases. However, approximately 71% of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism.

Q. How does RRA evaluate the regulatory environment in each jurisdiction?

A. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies that are regulated in each jurisdiction. RRA considers several factors that affect the regulatory process, including gubernatorial, legislative, and court activity; rate case decisions and other regulatory decisions; and information obtained through contact with commissioners, staff, utilities, and government outreach.

Q. Has RRA provided recent commentary regarding its regulatory ranking for Michigan?

A. In August 2024, RRA lowered its regulatory ranking of Michigan from "Above Average/3" to "Average/1," noting the following:

> While the jurisdiction remains more constructive than average from an investor viewpoint, ***the outcomes of certain recent rate proceedings could indicate a tightening in the regulatory climate***. RRA had placed the state on watch following a 2022 rate case decision in which the Michigan Public Service Commission (PSC) authorized DTE Electric Co. (DTE-E) an increase in rates that was less than 10% of that requested, but did not lower the ranking at that time. At the time RRA viewed the decisions to be an anomaly, as a

[42] MPSC Case No. U-21308, Direct Testimony of Laura M. Connolly, December 2022, at 13-14.

large part of the revenue requirement difference stemmed from reliance on a higher post-COVID sales forecast than the utility had used in its revenue requirement calculations. Even so, the company filed a new rate case less than three months later, asserting existing rates and projected electricity sales could not sustain its major capital investment program. Even though the outcome of the subsequent rate case was more constructive, DTE-E filed its third case in three years within four months (on March 28, 2024). The proceeding is pending and contends that current rates are not expected to provide it with adequate revenues to make necessary infrastructure investments while providing a reasonable opportunity to earn a fair return on equity. DTE-E is not the only company that has faced challenges in recent rate proceedings before the PSC. In a July 2, 2024 electric rate decision for Indiana Michigan Power Co., the commission authorized the company a rate increase that was about half what the company requested and kept its authorized ROE unchanged despite recent increases in interest rates. ***While the approved ROEs remain above prevailing industry averages, they compare less favorably to these averages, which have risen, albeit modestly, in recent periods***. The commission, nevertheless, does have several constructive practices have been in place: a streamlined rate case process; a framework for the utilization of forecast test years to reduce regulatory lag; and a framework that permits a cash return on certain construction work in progress, thereby reducing the uncertainty of cost recovery. Retail competition for electric generation is in place but is limited, and attempts to raise this limit have not been successful. Electric utilities have retained their generation assets, and customers who do not select a competitive supplier receive service on a regulated, traditional cost-of-service basis. Adjustment mechanisms are in place for fuel costs for customers served under bundled service. However, the courts have ruled against the authorization of revenue decoupling mechanisms for electric utilities. In the gas industry, the major local distribution companies have instituted programs that allow all retail customers to choose their gas supplier, and modest small-customer switching has occurred. The gas companies utilize periodic gas cost recovery mechanisms, and the PSC has authorized revenue decoupling mechanisms for certain gas utilities. Michigan's regulatory and political environments continue to support significant capital investments and

> timely recovery of these costs. RRA now accords Michigan regulation an Average/1 ranking[43]

Additionally, Company witness Bleckman's direct testimony provides additional detail on the credit rating agencies' assessment of Michigan's regulatory environment.

Q. What are your conclusions regarding the perceived risks related to the regulatory environment in Michigan?

A. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms, many of the companies in the proxy group have slightly more timely cost recovery between rate proceedings than Consumers Energy has in Michigan.

IX. CONCLUSION AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for Consumers Energy?

A. Figure 11 summarizes the results of my cost of equity analyses. Based on these results, the qualitative analyses presented in my direct testimony, the business and financial risks of Consumers Energy compared to the proxy group, and current and prospective conditions in capital markets, it is my view that an ROE of 10.25% is reasonable and would fairly balance the interests of customers and shareholders.

Q. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?

A. Yes. The level of earnings authorized by the Commission directly affects the Company's ability to fund its operations with internally generated funds. Both bond investors and

[43] Regulatory Research Associates, Profile of Michigan Public Service Commission, accessed August 6, 2024.

rating agencies expect a significant portion of ongoing capital investments to be financed with internally generated funds. In addition, it is important to recognize that because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long-term financing requirements of the assets placed into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. Therefore, both the ROE and capital structure are very important to debt and equity investors, particularly given the capital market conditions discussed previously. Company witness Bleckman's direct testimony explains the effect of the Company's authorized ROE and Equity ratio on credit quality.

Figure 11: Summary of Analytical Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	8.59%	9.87%	11.30%
90-Day Avg. Stock Price	8.79%	10.06%	11.50%
180-Day Avg. Stock Price	8.95%	10.23%	11.66%
Average	8.78%	10.05%	11.49%
Median Results:			
30-Day Avg. Stock Price	8.48%	9.83%	11.33%
90-Day Avg. Stock Price	8.72%	10.05%	11.57%
180-Day Avg. Stock Price	8.86%	10.17%	11.71%
Average	8.69%	10.02%	11.54%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.05%	11.04%	11.07%
Current Bloomberg Beta	10.15%	10.13%	10.20%
Long-term Avg. *Value Line* Beta	10.08%	10.06%	10.13%
ECAPM:			
Current *Value Line* Beta	11.30%	11.29%	11.32%
Current Bloomberg Beta	10.62%	10.61%	10.66%
Long-term Avg. *Value Line* Beta	10.57%	10.56%	10.61%
Bond Yield Risk Premium	10.22%	10.19%	10.35%

Q. Does this conclude you direct testimony?

A. Yes.

ATTACHMENT A

PRINCIPAL

Boston | 508.981.0866 | Ann.Bulkley@brattle.com

With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

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EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff and prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

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BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Southwest Gas Corporation	02/24	Southwest Gas Corporation	Docket No. G-01551A-23-0341	Return on Equity
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Company of Colorado	01/24	Public Service Company of Colorado	Docket No. 24AL-___G	Return on Equity
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
The Southern Connecticut Gas Company	11/23	The Southern Connecticut Gas Company	Docket No. 23-11-02	Return on Equity
Connecticut Natural Gas Corporation	11/23	Connecticut Natural Gas Corporation	Docket No. 23-11-02	Return on Equity
Connecticut Water Company	10/23	Connecticut Water Company	Docket No. 23-08-32	Return on Equity
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/24	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Illinois American Water	01/24	Illinois American Water	Docket No. 24-0097	Return on Equity
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	02/24	Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	Cause No. 46011	Return on Equity
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	12/23	Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	IURC Cause No. 45990	Return on Equity
Indiana Michigan Power Co.	08/23	Indiana Michigan Power Co.	IURC Cause No. 45933	Return on Equity
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
Iowa-American Water Company	04/24	Iowa-American Water Company	Docket No. RPU-2024-000_	Return on Equity
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-____	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	04/23	Evergy Kansas	Docket No. 23-EKCE-775-RTS	Return on Equity
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	11/23	Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	DPU 23-150	Return on Equity
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Upper Michigan Energy Resources Corporation	05/24	Upper Michigan Energy Resources Corporation	Case No. U-21541	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Michigan Gas Utilities Corporation	03/24	Michigan Gas Utilities Corporation	Case No. U-21540	Return on Equity
Indiana Michigan Power Co.	09/23	Indiana Michigan Power Co.	Case No. U-21461	Return on Equity
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
ALLETE, Inc. d/b/a Minnesota Power	11/23	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-23-155	Return on Equity
CenterPoint Energy Resources	11/23	CenterPoint Energy Resources	D-G-008/GR-23-173	Return on Equity
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Ameren Missouri	06/24	Ameren Missouri	File No. ER-2024-0319	Return on Equity
Evergy Missouri West	02/24	Evergy Missouri West	File No. ER-2024-0189	Return on Equity
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	01/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	01/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
Public Utilities Commission of Nevada				
Sierra Pacific Power Company d/b/a NV Energy	02/24	Sierra Pacific Power Company d/b/a NV Energy	24-02026	Return on Equity
Nevada Power Company d/b/a NV Energy	06/23	Nevada Power Company d/b/a NV Energy	23-06007	Return on Equity
Nevada Power Company d/b/a NV Energy	03/23	Nevada Power Company d/b/a NV Energy	22-03028	Merger benefits
New Hampshire - Board of Tax and Land Appeals				
Liberty Utilities (EnergyNorth Natural Gas)	07/23	Liberty Utilities (EnergyNorth Natural Gas)	Docket No. DG 23-067	Return on Equity
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
New Jersey American Water Company, Inc.	02/24	New Jersey American Water Company, Inc.	WR2401056	Return on Equity
Elizabethtown Gas Company	2/24	Elizabethtown Gas Company	GR24020158	Return on Equity
Public Service Electric and Gas Company	12/23	Public Service Electric and Gas Company	ER23120924 GR23120925	Return on Equity
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-W-0235	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Otter Tail Power Company	11/23	Otter Tail Power Company	Case No. PU-23-___	Return on Equity
Montana-Dakota Utilities Co.	11/23	Montana-Dakota Utilities Co.	Case No. PU-23-___	Return on Equity
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/23	Oklahoma Gas & Electric	Cause No. PUD2023-000087	Return on Equity
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	02/24	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-433	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	11/23	Pennsylvania-American Water Company	Docket No. R-2023-3043189 (water) Docket No. R-2023-3043190 (wastewater)	Return on Equity
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
CenterPoint Energy Houston	03/24	CenterPoint Energy Houston	D-56211	Return on Equity
AEP Texas	02/24	AEP Texas	D-56165	Return on Equity
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Texas Railroad Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
CenterPoint Energy Entex and CenterPoint Energy Texas Gas	10/23	CenterPoint Energy Entex and CenterPoint Energy Texas Gas	2023 Texas Division Rate Case Case No. OS-23-00015513	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	06/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 24-035-04	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/23	Virginia American Water Company, Inc.	Docket No. PUR-2023-00194	Return on Equity
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	03/24	Cascade Natural Gas Corporation	Docket No. UG-240008	Return on Equity
Puget Sound Energy Inc.	02/24	Puget Sound Energy Inc.	Docket No. UE-240004 UG-240005	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Power and Light	04/24	Wisconsin Power and Light	Docket No. 6680-UR-128	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/24	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-111	Return on Equity
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	08/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-671-ER-24	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

REDACTED

DIRECT TESTIMONY

OF

JESSICA R. BYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Jessica R. Byrom, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Customer Strategy.

Q. Please review your educational background.

A. I graduated from Michigan State University in 2008 with a Bachelor of Arts in International Relations and in 2015 with a Master of Business Administration.

Q. Please review your business experience.

A. In 2009, I began full-time employment with Michigan State University, working primarily in a human resources role during my tenure with the university. My role centered around process optimization and management of our hiring, firing, and compliance investigation processes for the department's 4,000 part-time and nearly 500 full-time employees. In 2017, I began my career at Consumers Energy as a member of the Customer Operations Strategy team. I was promoted to manager and eventual director of this team in March 2018. During my time with that team, I had the responsibility of working with the Company's business partners within the Customer Operations and Customer Experience teams related to goal creation, data organization, process optimization, testimony creation for rate cases, and the implementation of lean operating system framework. In September 2021, I took on the role of Director of Residential Demand Side Management, leading the team that owns and manages the products within the Residential sector for Energy Waste Reduction ("EWR") and Demand Response ("DR"). In June 2024 I took on the role of Director of Customer Strategy.

Q. What are your responsibilities as the Director of Customer Strategy?

A. In this position, I am responsible for implementation of the Company's lean operating system within the Customer organization, partnering with business units to improve Customer-related processes, and supporting the Customer business functions with executive communications.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I filed testimony on behalf of the Company in the following proceedings before the Commission:

Case No. U-21233	2021 DR Reconciliation;
Case No. U-21205	2021 EWR Reconciliation;
Case No. U-21321	2024-2025 EWR Plan;
Case No. U-21410	2022 DR Reconciliation; and
Case No. U-21647	2023 DR Reconciliation.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to describe the Customer Experience and Operations ("CX&O") organization and how the work performed within this organization benefits the Company's residential and business gas customers. As part of my direct testimony, I will address the operating and maintenance ("O&M") expenses and capital investments associated with executing this work in the test year ending October 2026.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (JRB-1)	Schedule B-5.3	Actual and Projected Capital Expenditures - Customer Experience & Operations;

Exhibit A-37 (JRB-2)	Summary of Actual & Projected O&M Expenses – Customer Experience, Customer Operations: Customer Interactions; and
Confidential Exhibit A-38 (JRB-3)	Summary of Actual & Projected O&M Expenses – Third-party ASP.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please describe Exhibit A-12 (JRB-1), Schedule B-5.3.

A. Exhibit A-12 (JRB-1), Schedule B-5.3, details the capital expenditures related to direct work within the CX&O organization, which totaled $111,000 in the historical year, $1 million projected in the bridge period, and $1.9 million projected in the test year. This reflects a financial forecast based on the work plan and designated development activities within the Customer Billing and Credit and Assistance areas.

Please note that this testimony also discusses the Customer Information Technology ("IT") project benefits related to the capital spend sponsored by IT Company witness Stacey H. Baker.

Q. Please describe Exhibit A-37 (JRB-2).

A. Exhibit A-37 (JRB-2) details the O&M expenses related to work within the CX&O organization, which total $32,000,000 for the test year ending October 31, 2026.

Q. Please describe Confidential Exhibit A-38 (JRB-3).

A. Confidential Exhibit A-38 (JRB-3) details the O&M expenses related to work within the third-party Appliance Service Plan ("ASP") space, with a total reported margin of $1.3 million for the test year ending October 31, 2026.

Q. Please describe Exhibit A-37 (JRB-2) page 4.

A. Exhibit A-37 (JRB-2), page 4, is a hypothetical illustration of the CX&O projected O&M expenses based on Inflation. This page is for illustrative purposes only and not intended to represent how the Company has developed its projected CX&O O&M. Column (b) shows the historical O&M expense. Column (c) shows the historical amount to which an inflation rate or merit increase rate was applied. Columns (e) and (g) show the amounts to which a hypothetical inflation rate or merit increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the hypothetical merit and inflation increases for each respective period. Because the Company does not develop the projected CX&O O&M using inflation it is necessary to include column (i), other adjustments. Column (i) is simply the difference between the Company's actual projected O&M and what the O&M would have been if the Company had used inflation to project CX&O O&M. Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i). The expenses that I am supporting are based upon the expenses necessary to meet the needs of the various projects and department operations planned in the test year and are not based on applying an inflation rate to the historical O&M expenses.

Q. Please describe how the CX&O budgets and projected O&M expenses are developed.

A. The budgets are prepared using a zero-base accounting method, meaning that they are prepared with no reference to any prior year's budget. To accomplish this, CX&O starts from zero and adds the expenses associated with the projects and department operation planned to complete in the test year to arrive at the final projected test year spend. By contrast, to conform to the Company's exhibit standard, Exhibit A-37 (JRB-2), page 4, must not start from zero but must instead start from historical year actuals, and, as a result, must have the "Other Adjustment" variable applied to it so that the final projected test year spend is the same as what is shown in the CX&O budget. Figures in this column should *not* be disallowed as though they are unjustified expenses. They do not exist as a category of spending, but merely reflect the difference in calculation methods between the CX&O budget and the hypothetical illustrations discussed above. Amounts included in the "Other Adjustment" column will be discussed throughout my testimony in the corresponding business area.

Q. Please provide a summary of the CX&O O&M expenses and capital investments projected in the test year.

A. CX&O is projecting capital expenses of $111,000 in the historical year, $1 million projected in the bridge period, and $1.9 million projected in the test year, as mentioned above, and $31.8 million in O&M expense for the test year ending October 31, 2026. This amount comprises $21 million of O&M expenses for Customer Interactions, and $10.8 million for Billing and Payment. The CX&O O&M expenses are presented in detail on Exhibit A-37 (JRB-2). The historical and projected capital costs for these programs are included in Exhibit A-12 (JRB-1), Schedule B-5.3.

DEPARTMENT	CAPITAL	O&M
Customer Interactions	$1.9 million	$21 million
Billing & Payment	$0.0	$10.8 million
Total	**$1.9 million**	**$31.8 million**

The Company is also projecting $438,000 in capital and $156,000 in O&M for customer capital investments in the test year to support the CX&O IT infrastructure. All IT-related capital costs discussed herein are in the IT budget and discussed by Company witness Baker.

Q. Has the Company undertaken any initiatives to lower costs related to CX&O O&M expense?

A. Yes. Incorporated into the CX&O O&M projection is $9 million of net recurring customer benefit to the gas business due to changes to the payment process. This is the result of implementation of a fee-based model for payments submitted through vendor payment channels to ensure the cost distribution for payments is fairly represented between residential customers and non-residential customers who choose to pay with a high-cost payment method or fee-based channels versus those who use fee-free payment methods.

Q. Are there remaining savings from the Company's Voluntary Separation Plan ("VSP")?

A. Partial year VSP savings (August-December) are still reflected in 2023 actuals, while the bridge and test year forecasts in my exhibits will also include VSP savings carried over from reduced headcount. Note that those savings are offset by yearly merit increases for remaining personnel.

Q. How is the remainder of your testimony organized?

A. My testimony is organized as follows:

I. Customer Experience and Operations
   A. Customer Interactions
   B. Billing and Payment

I. <u>CX&O</u>

Q. Please describe CX&O.

A. The CX&O organization strives to optimize the gas customers' positive experience when interacting with the Company. It has two major components - Customer Interactions and Billing & Payment. Customer Interactions ensures that customers are equipped to connect with the Company in their preferred channel (phone, Interactive Voice Response ("IVR"), website, mobile app, or digital correspondence—such as text messages). Billing & Payment provides customers with accurate, punctual energy bills and consistent payment processes, and arranges personalized payment plans or settings (e.g. inability to pay arrangements, pay by phone/website, payment alerts, choose your own bill due date) for individual customers.

These two core functions are fundamental to accomplishing the Company's customer experience goals. The Company relies on its array of customer experience offerings to ensure that customers are satisfied when interacting with Consumers Energy and are therefore positively inclined to enroll in its available clean energy programs. The Company recognizes the energy industry is increasingly expected, and committed, to pursuing clean energy and believes that customer engagement and participation is critical to realizing this future.

Q. Is the Company's IT witness sponsoring any Customer projects?

A. Yes. Company witness Baker is sponsoring test year funding for two Customer-related technology projects totaling $438,172 in capital expenditures and $156,343 in O&M expenses. Please see Company witness Baker's testimony for additional information.

The IT department is a critical CX&O partner and CX&O relies on IT expertise to help develop and implement necessary digital solutions. IT maintains the Company's technology systems, ensuring they operate efficiently, reliably, and free from cybersecurity risks. IT also supports analytic platforms and solutions that provide deeper insight into customer needs, enabling CX&O to establish appropriate targets for metrics, products, and customer programs, which are necessary to allow CX&O to select the most cost-effective and beneficial solutions for customers. Together, these departments ensure customers receive secure, reliable, and positive experiences across all channels of interaction with the Company. Continued investment in technology requires additional ongoing funding to initiate, support, and maintain these platforms. Cross-references to CX&O projects are noted below.

PROJECT	**CAPITAL**	**O&M**	**JRB-Testimony Reference**
Customer Order Service Tracker	$438,172	$150,951	DCO – page 11
Genesys Cloud Migration	$0	$5,392	DCO – page 13
Total	**$438,172**	**$156,343**	

A. <u>Customer Interactions</u>

Q. Please provide an overview of Customer Interactions.

A. Customer Interactions is responsible for the ownership and execution of all channels of customer interactions as identified above. This work includes the following areas of focus: Digital Customer Operations ("DCO"), Customer Contact Center, Business Customer Care ("BCC"), and Credit and Assistance. All are aligned to the larger department goals of: (i) providing customers the opportunity to interact with Consumers Energy via their channel of choice; (ii) facilitating program enrollment and product selection to meet customer energy needs; and (iii) achieving the Company's clean energy goals. To effectively perform in these areas, the Company is projecting $21 million of O&M expenses and $1.9 million in capital for the test year ending October 31, 2026, as shown on Exhibit A-37 (JRB-2).

1. <u>Digital Customer Operations</u>

Q. Please provide an overview of DCO.

A. DCO is responsible for the operation and continuous improvement of the Company's customer-facing digital applications, including its website and mobile application. The DCO team collects over 2,900 points of customer survey feedback every month, which drives the team's priorities in four simultaneous work cycles: (1) small, agile digital changes using available tools; (2) managing the design, development, and launch of monthly releases to add new features or modify user flows; (3) leading major technology projects that add new or modify existing functionality to better serve customers; and (4) executing the implementation of programs online to help accrue energy savings and clean energy opportunities for customers.

To continue this work, the Company is projecting $1.1 million of O&M expenses for the test year ending October 2026. As shown on Exhibit A-37 (JRB-2), this represents a decrease in O&M expenses of $800,000 from the $1.9 million expended in 2023. The primary driver of this is a decrease in contractor-related costs.

Q. What types of transactions do customers complete online?

A. The most common transactions customers complete using the Company's website and mobile app are: (1) checking the billing status of their account (12.8 million views in 2023); (2) making payments (13.3 million views in 2023); (3) reporting outages or view the status of an outage (4.7 million views in 2023); (4) checking energy usage information (1.3 million views in 2023); and (5) investigating additional service information—such as auto-pay, eBill enrollment, budget billing, and information on products and services. The Consumers Energy website also serves as the principal vehicle to enable customers to sign up for clean energy program rebates, enroll in energy saving programs, and save money with energy-efficient products.

Q. Please explain why the Company is continuing to invest in multiple digital methods to allow customers to complete transactions or find information in their channel of choice.

A. The Company continues to invest in multiple digital methods for customer interaction for several reasons. Continued investments are needed to keep pace with changes in customer needs, habits, and expectations at the same time customer use continues trending toward more integrated and sophisticated digital services. These investments also ensure channel parity so that customers can complete all transactions in all channels. Additionally, expanding the Company's digital channel lets customers complete a variety of activities on a smartphone or computer at a time that may be more convenient than the limited call center service hours, shifting costs to the more cost-effective channel. In 2023, customers paid $4.7 million of bills through the web and mobile app daily. Both channels together are on track to see $1.7 billion in payments yearly. Online transactions cost approximately $0.11 versus $9.22 per live agent call (utilizing internal contact center resources), making this a cost-effective alternative to expanding the call center service hours.

The Company's digital channels are critical systems requiring proper levels of support to ensure they function when and how customers need them. It is important to note that, like most peer institutions for which this has become the customer expectation, the Company continues to support several channels in response to customer needs and choices for communicating and completing transactions. The Company's IVR System currently co-exists in the digital platform space with the website/mobile website and the mobile app. Similarly, the Company maintains call centers and direct payment offices for customers who prefer to communicate or pay face-to-face. Many of these channels are maintained in service of the wide variety of customer needs given generational, locational, and socio-economic factors.

Q. Is the CX&O department proposing test year IT costs related to DCO projects?

A. Yes. Company witness Baker is sponsoring test year capital IT costs for two DCO projects: (i) $438,172 in capital and $156,343 in O&M costs in the test year for the Company's Customer Order Service Tracker, and (ii) $55,000 in O&M for Genesys Cloud Migration. The customer benefit of each project is discussed below.

<u>CUSTOMER ORDER SERVICE TRACKER</u>

Q. Please detail the Customer Order Service Tracker.

A. The Customer Order Service Tracker will implement a service order status tracker to provide both transparency to customers and oversight to internal teams supporting utility service orders across Company service areas. The tracker will provide timely and accurate service order updates, creating a more robust customer experience for tracking service order status and crew location updates, as well as an interactive digital channel for use by dispatch, scheduling, and field crews.

Many incoming customer inquiries include "short cycle" orders, such as questions about or reports of emergencies, forestry needs, or meter services issues. Customers may have very limited visibility into when Company-assigned crews will be onsite for this work due to a current lack of relevant features within the Company's digital channels that can track and report accurate updates from dispatch, scheduling, and field crews. The lack of awareness drives thousands of short cycle request-related calls into the call center.

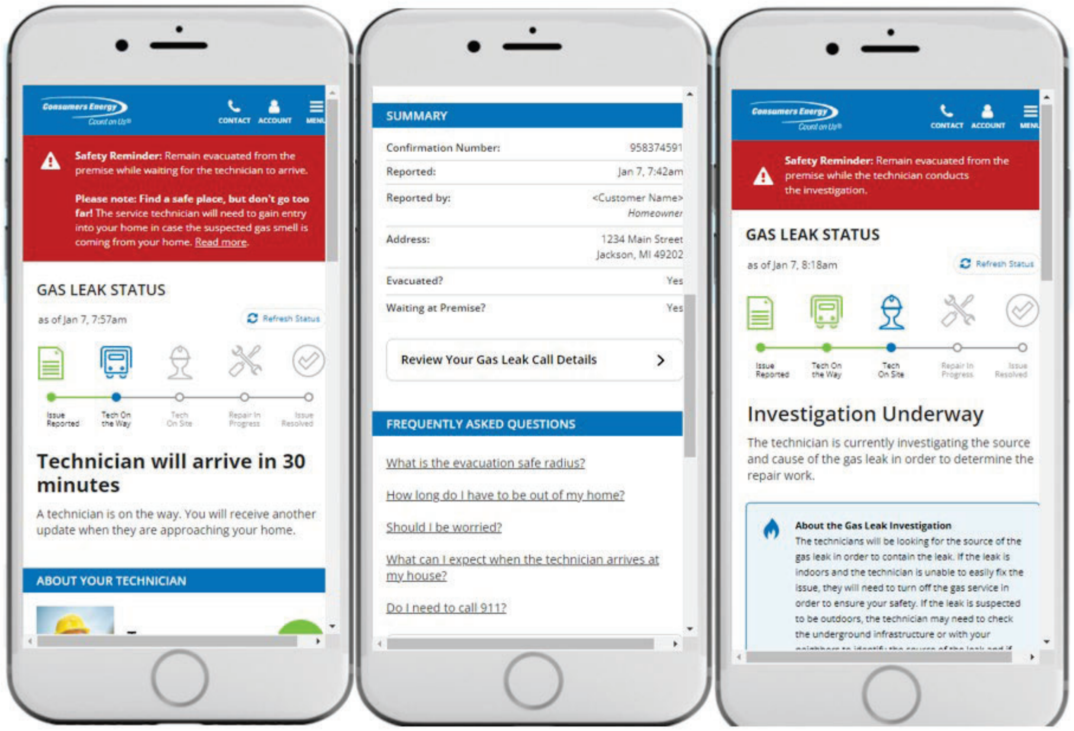
Additionally, current lack of visibility by dispatchers increases truck rolls because they have limited awareness of crew locations and routes, which can cause crews to be assigned improperly. Enabling a digital channel for utility service order communication for both customers and dispatchers will improve customer experience and reduce the waste of repetitive crew dispatching.

Q. Why is this project important in the customer space?

A. This project will add value to the Company and its customers by: (1) providing transparency for customers on the timing and location of the associated crew completing utility service orders; (2) reducing calls to contact centers by customers seeking clarification regarding arrival times through visibility to scheduling timeframes and providing notifications to customers when crews are enroute; (3) improving resource assignment by current location, which decreases wasted truck rolls through enabling location services for active crews; (4) increasing visibility into the service person(s) completing the order by enabling crews to connect with customers through digital channels; and (5) improving customer experience for short-cycle service orders by implementing a channel of choice for Company interactions.

Helping the customer to understand where their request is in the process reduces frustration by providing a clear view into their order. This project seeks to offer a simple, informative option which the customer can easily access and check.

The images below are mock-ups of the potential user experience flow, designed around a mobile device user in a gas leak emergency.



Q. Are there additional benefits to the Customer Order Service Tracker?

A. This project will provide transparency on the timing and location of the assigned crew completing utility short-cycle service orders. As a result, use of the tracker will reduce calls from customers seeking clarification by scheduling and communicating arrival timeframes and providing notifications when crews are in-route; improve resource assignment, decreasing wasted truck rolls; and allow crews to connect with customers through digital channels.

<u>GENESYS CLOUD MIGRATION</u>

Q. Please detail the Genesys Cloud Migration Project.

A. Genesys, the Company's on-premises software solution for receiving and managing customer phone calls, is in need of costly upgrades but vendor support for the tool will end in 2028, with no option for extended support. Without such support, the system will no longer receive critical security patches or software "bug fixes" from the vendor which then creates significant security, stability, and reliability risks in addition to limiting the Company's ability to invest in new functionality to better serve customers. This project will migrate the Company's existing solution to the cloud, ensuring that vendor security patches, bug fixes, updates, and enhancements are deployed as necessary, allowing the Company to ensure continued support for this critical customer communication channel.

In addition to continued support, the Company will save approximately $150,000 in managed service costs and over $1 million in licensing costs over the next three years, while also avoiding the significant costs necessary to maintain an on-premises solution. The cloud solution will also allow the Company to take advantage of new enhancements offered by the vendor and ensure continued support of a critical customer communication channel.

<u>CUSTOMER PRODUCT FAMILY ENHANCEMENTS</u>[1]

Q. Please describe how Customer Product Family enhancements are identified and implemented.

A. CX&O Customer Product Family Enhancements are technology improvements which benefit customers and are implemented in response to the launch of a channel, customer tool, project completion, and/or direct customer feedback. Depending on the need identified, enhancement dollars could be utilized to support the enhancement of any customer supporting feature and/or capability, often as emerging requests. These items are small-scope items with a reduced budget and fewer resource requirements in comparison to larger capital investments. Having the flexibility to implement Customer Product

[1] For 2021 and 2022, the actual project name was Enhancements-CX&O-Capital and starting in 2023, the project is named Product Family Enhancements-Customer-Capital.

Family Enhancements enables the Company to meet emerging needs without the longer lead time of rate case submissions.

Examples of enhancements include improving overall functionality of the channel or tool, analytics on platform usage, addressing issues identified internally or via customer feedback, adding relevant or customer-driven capability, and performance monitoring.

Q. How do Customer Product Family Enhancements benefit the Company's customers?

A. Enhancements assist the Company in providing a better, more optimized customer experience for customers through improved understanding of how they use the channels or tools, which features are important to their experience, and how the channels or tools are performing. Specific enhancements are discussed throughout my testimony in the corresponding business area and IT Company witness Baker's testimony.

2. <u>Customer Contact Center</u>

Q. Please provide an overview of the Customer Contact Center.

A. The Customer Contact Center is responsible for staffing and operating the Company's call centers, which serve all residential and small business customer calls. In 2023, call center representatives answered over 2.75 million customer calls. Likewise, the IVR system addressed 5.1 million calls in 2023.

To continue this work, the Company is projecting $13.2 million of O&M expenses for the test year ending October 2026. As shown on Exhibit A-37 (JRB-2), this represents an increase in O&M expenses of $245,000 from the $13 million expended in 2023. Most of the increase is due to increased contractor cost.

3. <u>Business Customer Care</u>

Q. Please provide an overview of BCC.

A. BCC directly impacts the Company's commercial and industrial ("C&I") customers, and includes the Business Center, which assists the Company's larger business customers with support such as phone agents and account management. BCC's main goal is to deliver an exceptional customer experience, while identifying opportunities that provide the Customer with added energy value and opportunities. Overall, BCC serves approximately 100,000 customers, equating to 200,000 contract accounts.

To continue the work in this area, the Company is projecting $1.78 million in O&M expenses for the test year ending October 2026. As shown on Exhibit A-37 (JRB-2), this represents a decrease in O&M expenses of $50,000 from the $1.83 million expended in 2023, with the decrease attributed to lower labor costs in this area.

4. <u>Credit and Assistance</u>

Q. Please provide an overview of Credit and Assistance.

A. Credit and Assistance consists of: (1) Theft Investigations; (2) Revenue Operations; and (3) Energy Assistance, which collectively manage the Company's collections cycle and support its most vulnerable customers by connecting them with Company-sponsored payment plans and public assistance funding to help customers pay their bills.

The Theft Investigation Team provides the critical service of identifying and ending energy theft in the Company's service territory - important both for maintaining the safety and integrity of the Company's system and minimizing all customers' costs. In 2023, the team identified 2,797 confirmed cases of theft and billed for $1,145,650.81 in unauthorized use and investigation costs - an increase of 1,487 cases and an increase of about $473,000 billed over the previous year.

Revenue Operations addresses past due customer accounts or those involved in bankruptcy. Employees within this area manage the collections cycle, beginning with issuing a notice to customers and ending with visiting their premises to disconnect service. This group also manages contracts with outside collection agencies to recover payments from customers with outstanding balances. In 2023, the Company contracted with outside collection agencies for $2.1 million (covering recovery for both gas and electric accounts). Consequently, the agencies recovered $8.8 million of previously written-off customer balances, of which $2.9 million accounted for *gas-only* recoveries (33% of total). Recovery of these payments directly offsets the uncollectible expense discussed in the testimony of Company witness Matthew J. Foster.

The Energy Assistance team is responsible for administering the Company's Consumers Affordable Resource for Energy ("CARE") Program, which supports low-income customers who may be struggling to pay their monthly energy bills and helps to provide customers with either a one-time bill assistance payment or on-going support via enrollment in an Affordable Payment Plan ("APP"). By coordinating with other organizations in fiscal year 2023, this team obtained $10.4 million of APP-specific assistance and an additional $9.2 million in one-time assistance for its customers requested through the Michigan Energy Assistance Program ("MEAP"). These plans offer customers reduced monthly bills and gradually pay down any arrears brought into the program. In addition to MEAP assistance, customers received $37.8 million in State Emergency Relief payments and $18.9 million in Home Heating Credit assistance. Note these figures include assistance for both electric and gas customers.

To continue the work in this area, the Company is projecting $2.6 million in O&M expenses and $1.9 million in capital for the test year ending October 2026. As shown on

Exhibit A-37 (JRB-2), the O&M request represents an increase of about $300,000 in O&M expenses from the $2.3 million expended in 2023, due to increased labor and contractor costs.

Q. Please provide additional details about the $1.9 million in capital spending in this area.

A. The capital request is to support the Low Moderate Income ("LMI") Customer Support Enhancement.

Q. Please describe the LMI Customer Support Enhancement project.

A. The LMI Customer Support Enhancement project aims to provide solutions that make interactions more accessible, supportive, and efficient, while facilitating enrollment into assistance programs to reduce energy burden for LMI customers. This project will facilitate reaching customers earlier and significantly easing the enrollment process to payment assistance and income-qualified programs including budget plan, payment arrangements, shut-off protection, home energy audits, helping neighbors, demand response, renewable energy and more, by (1) implementing a streamlined, self-attestation workflow that allows customers to find and enroll in *all* relevant assistance programs, and (2) building the capability to proactively identify and reach out to customers who are showing early signs of crisis, educating them about assistance options and directing them to the streamlined, digital workflow. This project aims to address identified barriers to earlier LMI interaction and enrollment in utility programs.

Q. What is the purpose of the LMI Customer Support Enhancement project?

A. The LMI Customer Support Enhancement project is designed to support low and moderate-income customers to reduce their utility bill expenses by driving greater awareness and enrollment into eligible programs and services. The central purpose is to alleviate the energy burden these customers face to improve household stability and reduce the risk of service disconnections due to unpaid bills.

Q. Why is it important for the Company to receive approval for this project?

A. This project will directly improve the customer experience by supporting a significant portion of the Company's customer base: low- to moderate-income customers. LMI customers account for more than one of every three customers in Consumers Energy's service territory; 11% are low income, meaning they are in crisis and unable to pay their energy bill; 26% are moderate income, commonly identified as being one crisis away from being able to pay their energy bill. Currently, only one in six LMI customers engage in Consumers Energy Assistance programs with the majority of these interactions driven by immediate crises that limit ability to introduce solutions and programs given the urgent customer need. Further, interactions at near crisis and crisis moments impacts trust, often resulting in customers being less receptive and open to solutions the Company can offer or provide access to.

Moreover, approval of this project delivers on the priorities of the MPSC's Energy Affordability and Accessibility Collaborative (EAAC) and Low-Income Energy Policy Board that highlight the importance of streamlining energy assistance and program enrollment processes to support increased awareness, participation, and customer benefit. This need for attention to simplified and effective processes is also highlighted in Public Act 229 of 2023, which instructs utility EWR programs to minimize barriers to participation in low-income EWR programs and reduce overly burdensome verification processes.

Overall, this work will provide proactive, immediate relief, helping these customers manage costs, avoid disconnection, and maintain essential services. All of which will enhance customer well-being making it a socially responsible initiative with tangible, positive outcomes.

Q. Describe the customer research used to develop the project.

A. To address the dynamics previously stated, the Company initiated primary and secondary research to better understand LMI customers to identify barriers, increase awareness about assistance options and increase participation in utility programs. The Company used existing research from a variety of partners which established a clear need for the LMI Project, and the LMI project team then undertook primary research to validate and refine the learnings. The primary research included more than 2,000 LMI customers, 95% of whom live in Michigan. Through surveys, interviews, and ethnographic studies these customers shared insights on their experiences, challenges, and expectations, ensuring the project is informed by the voices and needs of those it aims to serve.

Research findings revealed that 18% of LMI customers are unaware of how to access help, 36% are unaware they qualify for programs, 25% perceive the process as overly complex and time-consuming, 51% feel too overwhelmed to take on another project, 21% consider EWR programs to be price-prohibitive, and 46% are unfamiliar with utility assistance for low-income families. Furthermore, research from a 2024 Los Angeles Dept. of Water and Power case study showed that using income self-attestation increased program enrollment and willingness to initiate assistance requests by 40%. Customer research was foundational in the development of this project to ensure outputs are not only accessible and effective but also directly address the needs and preferences of LMI customers, ultimately making it a valuable tool for reducing utility bills and supporting financial stability.

Q. How will investment in this project benefit customers?

A. While this project's primary focus is to support LMI households, its results will benefit all customers. There are five key customer benefits this project will deliver. First, enhancing energy equity: by broadening access to bill assistance and utility programming this solution gets us one step closer to ensuring everyone has equal access to basic utilities. Second, addressing the risk of unpaid bills and service disconnections isn't just compassionate and the right thing to do, it's also cost-effective; preventing service cuts reduces administrative costs and lost revenue which will positively impact all customers. Third, building trust with LMI customers fosters a sense of loyalty and increases their willingness to engage proactively, not just in times of crisis. Fourth, reducing the bill and energy burden on low-income families enhances their overall quality of life and financial stability. Finally, engaging LMI households not only in bill assistance programs but also in clean energy solutions is crucial for environmental sustainability aligning with the Company's Clean Energy Plan and the state's MI Healthy Climate Plan. Together, these benefits not only support vulnerable customers but also create a more cost-effective and sustainable future for everyone.

Q. Does this project have internal approval?

A. Yes.

<u>Billing and Payment</u>

Q. Please provide an overview of Billing and Payment.

A. Billing and Payment is responsible for leveraging customer feedback to ensure payment processes are simple and consistent, monthly energy bills are accurate and easy to understand, and customers receive their bills in a timely fashion. The work in this department is divided between Customer Billing and Customer Payment programs. The

Company is projecting $10.9 million of O&M expenses for the test year ending October 2026. As shown on Exhibit A-37 (JRB-2), this represents a decrease in O&M expenses of approximately $4.2 million from the $15 million expended in 2023. This decrease is mainly due to the Company's policy shift in assessing credit card fees.

1. <u>Customer Billing</u>

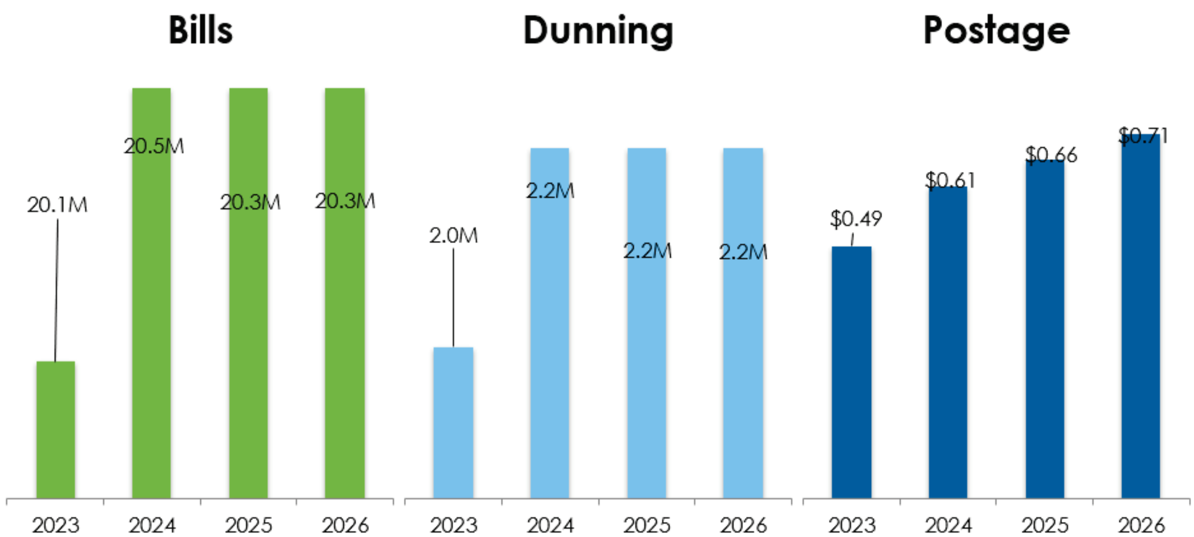
Q. Please provide an overview of Customer Billing.

A. Customer Billing manages the exceptions process - a quality control process designed to (1) review unusual bills (both digital and paper) and/or (2) bill for unique programs before they are sent to customers. The review may involve contacting customers to gather additional information or to inform them of a potential billing issue. Bills may be corrected through the billing adjustment process, or meters may be reread as part of the validation process. Rigorous efforts to ensure every customer bill is accurate results in the Customer Billing team continually optimizing its processes and technology to aid in the billing exception review. Ensuring that customers receive the right bill every time is critical. To continue this work, the Company is projecting $9.5 million of O&M expenses for the test year ending October 2026. As shown on Exhibit A-37 (JRB-2), this represents an increase of $805,000 from the $8.7 million expended in 2023, due to a US Postal Service postage increase in 2024 as well as a projected increase in 2025.

Q. Please explain the costs within Customer Billing.

A. The cost for stationery, forms, and postage related to the Company's billing and dunning communication processes is included in Customer Billing. In 2023, the Company mailed nearly 20.5 million paper bills, and approximately 2 million dunning notices. As illustrated in Figure 1 below, the Company has incurred increased postage rates in recent years, and the increased costs of additional dunning notices being mailed.

Figure 1. Current and Projected Dunning and Postage Costs



To mitigate these cost increases, the Company has taken action to increase customer enrollment in electronic billing, or eBill. Consumers Energy has successfully increased eBill participation from <27% in 2017 to 48% as of the fourth quarter of 2023. This growth has offset postage costs by over $2.5 million annually by reducing the number of pieces mailed.

However, cost per piece of postage has steadily increased over the past three years, a cost expected to continue to increase due to US Postal Service postage increases. These increases offset the savings the Company has realized from growing its eBill enrollment, without which increases in the cost for postage would have contributed to the cost of customer billing over time. In addition, as shown in Exhibit A-37 (JRB-2), the Company invested $1,078,000 in the bridge period on printers used for two large-scale customer bill printer replacements. Two of the Company's printers reached the end of life in 2023, and it was necessary to replace them to continue to be able to provide customers with appropriate and timely bills.

2. Customer Payment Programs

Q. Please describe the CX&O Customer Payment Programs group.

A. Customer payments are among the most sensitive and frequent touchpoints the Company has with its customers, with approximately 34 million payments made annually. The Company's Customer Payment Strategy focuses on removing payment difficulties, providing payment options that customers expect, and ensuring all customers have the same easy payment experience regardless of how they choose to pay their bill. This has resulted in a significant reduction of payment-related calls and complaints and improvement in customer experience. The Company continues to make it a priority to accommodate customer preferences with a variety of desirable options to meet current customer expectations and to maintain a single set of customer-friendly payment rules that apply across all payment options.

Q. Please describe the costs associated with the Customer Payment Programs.

A. The Company is projecting $1.4 million in the test year O&M expenses shown on Exhibit A-37 (JRB-2). This represents a $5 million decrease from the $6.4 million expended in 2023. The decrease is mostly due to ending the socialization of credit card fees. Operating costs associated with customer payments continue to evolve with changes in customer behaviors and preferences.

Q. What are the anticipated payment processing fees costs for the test year?

A. Within the $1.4 million of Customer Payment Programs test year O&M expense, the Company is projecting $192,766 in payment processing fees O&M expenses for the test year. Additional payment-related fees include bank lock box fees in the amount of $364,560, approximately $497,169 in Direct Payment Office ("DPO")-related payment fees, and $321,412 for the Billing & Payment Program Support team.

Q. Are there additional changes to the way the Company collects payment processing fees?

A. As discussed above, the Company has implemented a policy change, resulting in a fee-based model for payments submitted through vendor payment channels.

Q. Does the Company anticipate any revenues generated by assessing payment card service fees to customers continuing to pay with a credit/debit card?

A. No, the Company does not anticipate or forecast any revenue being generated from payment processing fees.

Q. What are the merchant fees that customers pay for use of credit/debit cards?

A. All customers using credit/debit cards pay a flat fee per transaction. Residential customers pay $2.99 per transaction and C&I customers pay $9.99 per transaction, regardless of rate schedule. These fees are paid directly to the third-party payment processor, Paymentus.

Q. Please provide an overview of DPOs.

A. Consumers Energy has eight DPOs around the state of Michigan, all located within existing Company facilities, making them a cost-effective option for customers to pay their bills in person. These offices serve some of the Company's most vulnerable customers, such as seniors and low-income customers, providing them with a community resource that can connect them with billing options and assistance opportunities.

Q. Does the Company offer other in-person payment options in addition to the remaining DPOs?

A. Yes. The Company has maintained its relationship with an authorized pay agent, which accepts payments at stations such as Wal-Mart, Kroger, and other associated store fronts. These pay stations serve as de facto DPOs. This provides customers with the continuity and convenience of being able to pay their bill without having to locate a DPO. Customers are charged a fee to pay their bill in these locations, which covers the costs of the processing fee the Company is charged to have this option.

Q. Does the Company itself collect the payment fee?

A. It does not. The authorized pay agent implements and collects the fee from the customer utilizing their services.

Q. What is the payment fee?

A. The payment fee is $1.50 per transaction, per the agreement between the vendor and the Company.

<u>HOME ENERGY PRODUCTS PROGRAM</u>

Q. Please describe the Company's Home Energy Products Program.

A. Home Energy Products referred to a portfolio of value-added products and services ("VAPS") that consists of the Company's non-regulated ASP, appliance repair, and the AllConnect Mover Program. Customers enrolled in ASP paid a monthly subscription fee to cover repairs to equipment such as furnaces, air conditioners, etc. and if a covered appliance malfunctioned, a qualified service person was sent to explain/rectify the problem at no additional cost to the customer. This program benefitted customers by reducing the risk of potentially expensive and unexpected appliance repair or replacement costs.

Q. In the Company's last gas rate case (Case No. U-21490), Company witness Heidi J. Myers and Steven Q. McLean testified regarding the sale of portions of the Company's Home Energy Products Program. Was the sale successfully completed?

A. Yes. The sale was successfully completed.

Q. Were the proceeds shared with customers as detailed in U-21490?

A. Yes. The proceeds were shared with customers as defined in the Commission's July 23 Order in Case No. U-21490, approving a settlement agreement that states:

> The parties agree that Consumers Energy shall share 100% of the net upfront gain of approximately $110 million with customers in the following manner, without interest. $27.5 million, or one fourth of the net upfront gain, shall be used as an offset to the revenue deficiency in lieu of additional rate relief during the test year. The remaining three fourths of the net upfront gain, approximately $82.5 million, will be credited back to customers, through the Home Products Credit over a three-year period starting with the test year . . .

[Start Confidential]

[redacted]

[End Confidential]

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. In what capacity are you employed?

A. I am employed as the Director of Compensation Operations for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. I graduated from Central Michigan University in 1999 with a Bachelor of Science Degree in Business Administration with a major in Accounting. In addition, I am designated as a Certified Compensation Professional and Certified Executive Compensation Professional by WorldatWork and a Certified Public Accountant by the Michigan Association of Certified Public Accountants. WorldatWork is an international professional organization focused on human resources issues, including compensation, benefits, work life, and integrated total rewards to attract, motivate, and retain a talented workforce.

Q. What have your job responsibilities entailed with Consumers Energy?

A. In February 2002, I joined Consumers Energy as a Financial Reporting and Technical Accounting Analyst. My duties included accounting and reporting of equity-based compensation, technical accounting standard research, and preparation of quarterly and annual Securities and Exchange Commission ("SEC") filings. After eight years of progressing responsibilities in this role, I transferred to the position of Principal Human Resources Consultant. In 2013, I was promoted to the position of Director of Compensation. In this role I had the responsibility for administering Consumers Energy's compensation function and partnering with Labor Relations on union compensation matters. This included developing compensation programs designed to attract and retain a qualified workforce for the Company. My duties included gathering of comparable wage and salary data in order to determine how Consumers Energy's pay level compares to the labor market and developing compensation programs that are competitive and deliver pay to employees that is fair and equitable and that motivates employees to perform at their full potential.

My responsibilities also consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers.

In May 2018, I took on the role of Director of Executive and Incentive Compensation. My responsibilities consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers. My responsibilities also included administering the incentive plans for CMS Energy, including Consumers Energy.

In August 2023, I took on the role of Manager of Compensation Operations. My Manager of Compensation Operations responsibilities consisted of the implementation of new and revised non-officer compensation programs, policies, and procedures for non-officers to align with the Company's goals and competitive practices. This position is also responsible for ensuring that compensation programs are consistently administered in compliance with internal policies and government regulations. The Manager of Compensation Operations role focuses primarily on the coordination and implementation of the non-officer merit, incentive, stock administration, survey participation, and ensuring accuracy of data for non-officer programs.

In January 2024, I took on the role of Director of Compensation. My Director of Compensation responsibilities consist of the implementation of new and revised officer and non-officer compensation programs, policies, and procedures for officers and non-officers to align with the Company's goals and competitive practices. This position is also responsible for ensuring that compensation programs are consistently administered in compliance with internal policies and government regulations. The Director of Compensation Operations role focuses primarily on the coordination and implementation of the officer and non-officer merit, incentive, stock administration, survey participation, and ensuring accuracy of data for officer and non-officer programs. Lastly, the Director of Compensation consists of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have testified in Case Nos. U-17087, U-17197, U-17643, U-17735, U-17882, U-17990, U-18124, U-18322, U-18424, U-20134, U-20322, U-20650, U-20697, U-21148, U-21224, U-21308, U-21389, and U-21490.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for costs of its annual Employee Incentive Compensation Plan ("EICP") at target levels. The EICP is a form of short-term incentive. Short-term incentive pay is designed to focus and reward performance over periods of approximately one year or less.

First, I will discuss Consumers Energy's overall compensation philosophy. In this section of my direct testimony, I will discuss the importance of paying employees a competitive level of compensation and the reasonableness of the overall compensation levels that the Company is requesting in this case. In addition, I will discuss (i) the fact that EICP compensation is part of an employee's overall market-based compensation and not in addition to it, and (ii) why Consumers Energy has included EICP at target levels as part of overall market-based compensation.

Second, I will discuss the EICP incentives and provide support for the Company's request for rate recovery in this case related to Consumers Energy's non-officer and officer operational goal portion of EICP. In my direct testimony, I will discuss the design of the EICP.

Third, I will discuss customer-related benefits that result from use of the incentive plans and how customers are best served when Consumers Energy can attract, retain, and motivate a talented workforce with compensation packages that are competitive and fair. Elimination of the EICP would result in Consumers Energy's employee compensation being below market and would hinder the Company's ability to attract and retain a qualified workforce that best serves customers.

Q. Please summarize your conclusions.

A. My conclusions include the following: (i) use of incentive compensation by utility companies is an accepted, common, and reasonable practice; (ii) Consumers Energy's decision to make a portion of compensation at-risk and subject to incentives is reasonable;

(iii) the amount of overall compensation included by Consumers Energy in this case is reasonable and is reasonably necessary to attracting and retaining a talented workforce; (iv) incentive compensation is part of the reasonable level of market-based compensation and not in addition to it; (v) recovering costs of Consumers Energy's EICP employee incentive plans will not result in excess rates; (vi) Consumers Energy's EICP performance goals and thresholds provide customer-related benefits; and (vii) the EICP goals provide customer-related benefits at no incremental cost to customers above those included in market-based compensation.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-39 (AMC-1)	EICP Performance Measures;
Exhibit A-40 (AMC-2)	Target Pay Level Market Analysis; and
Exhibit A-41 (AMC-3)	Summary of Actual and Projected – Annual Incentive O&M Expenses.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

I. OVERVIEW

Q. What is the Company's compensation philosophy for non-officer employees?

A. Consumers Energy's compensation philosophy for its non-officer, non-union employees is to provide market-based compensation tied to performance. A competitive compensation policy benefits customers by attracting and retaining employees with the necessary skills and experience to deliver world-class customer service and minimize the risks and costs of employee turnover. Incentive pay is a component of providing market-based compensation.

Q. What is the Company's compensation philosophy for officer employees?

A. Consumers Energy's compensation philosophy for its officers is centered around four principles:

1. Align with increasing shareholder and customer value;
2. Enable the Company to compete for and secure top executive talent;
3. Reward measurable results; and
4. Be fair and competitive.

Incentive pay is a reasonable component of delivering this philosophy.

Q. How does Consumers Energy structure non-officer compensation for its salaried employees?

A. Consumers Energy first determines what a competitive level of pay is for salaried non-officer employees. It does so by using various market surveys. The practice of using multiple surveys is common practice. It allows for a broader participant pool and confirmation that the survey data is representative of market competitive wages and trends. Consumers Energy then structures the compensation by allocating this market-based wage between base salary and incentive compensation. The incentive compensation is part of the overall total market-based competitive level and it is not in addition to it.

Q. How does Consumers Energy structure officer compensation?

A. Officer compensation levels are determined by the Compensation Committees of the Boards of Directors of Consumers Energy and CMS Energy. The Company creates a compensation package for officers that delivers base salary, annual incentive compensation, and long-term incentive compensation targeted at the median or 50th percentile of the competitive market. In determining individual officer compensation levels, the Compensation Committees are advised by an independent third-party consultant and take into consideration market research, experience levels, and individual contributions.

Q. In this proceeding, is the Company requesting rate recovery of all Operating and Maintenance ("O&M") gas expenses related to short-term incentive compensation plans?

A. No. The Company utilizes both financial and non-financial (operational) goals in its short-term incentive compensation plan. While the Company believes that both financial and non-financial (operating) short-term incentive compensation expenses are reasonable, the Company in this case is excluding the costs of short-term incentive compensation linked to financial goals ($7.6 million). Included in that $7.6 million amount is the removal of the affordability (O&M savings) operational measure. The Company determined that the affordability measure, although included among the Company's operational goals for purposes of the EICP, is financial in nature; therefore, the Company removed the dollars attributable to that measure from the rate request in this case along with the dollars attributable to the other financial measures.

Q. Is Consumers Energy requesting recovery of all officer incentive pay linked to non-financial (operational) goals in this rate case proceeding?

A. Yes. The Company in this case is seeking recovery for the incentive costs associated with the operational goals portion for all officers. This is a result of 30% of officer pay directly linked to operational measures. In prior cases, the Company excluded the top five officers, but sought recovery of all measures which were 100% financial with a modifier to the non-officer non-financial goals.

Q. Is Consumers Energy requesting recovery of long-term incentive pay in this rate case proceeding?

A. No. The Company is not seeking recovery for the costs of long-term incentive compensation (sometimes referred to as restricted stock plans) in its rate recovery request in this case.

Q. Why is the Company requesting rate recovery of short-term incentive compensation operational goal expenses?

A. Consumers Energy uses market data to determine an overall competitive level of compensation. Competitive compensation includes base salary and short-term incentive compensation for officers and non-officers. Consumers Energy's overall compensation levels are reasonable compared to the market. Compensation levels without these incentive payments would be below market competitive levels. Paying non-competitive levels of compensation would result in a less qualified workforce that would not best serve customers. A November 2021, Wall Street Journal entry stated:

> Many senior executives are struggling with an urgent talent crisis: The Great Resignation. The COVID-19 pandemic has induced waves of people to quit their jobs, seemingly in search of more meaning, more money, and more flexibility, among other wish-list items. The labor and skills shortage is now so severe that CEOs rank it as the No. 1 external issue they expect to influence or disrupt their business strategy within the next 12 months.

In order to hire and retain qualified personnel, it is necessary to either pay a competitive incentive or increase base salaries to make up for the missing incentive compensation component. Use of annual incentive mechanisms is a recognized management technique for companies, including utility companies. As I discuss later in my direct testimony, incentive pay is the number one compensation design element used to influence short- to mid-term performance results. Incentive mechanisms help communicate priorities, engage the employees in operating and financial success, reward valued skills and behaviors, and create business understanding for employees. Consumers Energy's incentive programs are structured in a way that is designed to help keep non-officers and officers focused on operational performance areas such as continuous improvement, safety, cost, reliability, and delivery. The incentive compensation program encourages employees to deliver outcomes which result in meeting customers' expectations. The EICP incentive compensation costs are reasonable costs of doing business and, therefore, should be recovered in rates.

Q. Who is eligible for the EICP incentives?

A. All non-union employees are eligible for EICP incentives, with the exception of employees who are rated as "under-contributing" or "needs improvement" on their annual performance appraisals. These under-performing employees are ineligible to receive an EICP incentive. Both non-officers and officers participate in an annual EICP incentive.

Q. How are the EICP incentives structured?

A. The EICP incentives are structured by non-officer and officer EICP. The 2023 non-officer EICP equally weights the operational measures with the financial measures:

- Half (50.0%) of employees' incentive will be based on the achievement of operational performance measures. (For 2023 and 2024, there are six operational measures.); and
- Half (50.0%) of employees' incentive will be based on the achievement of one financial measure, Earnings Per Share ("EPS"). Consumers Energy is a vital part of the Michigan economy, and it is important that the utility remains financially strong so that it can provide the utility service that customers expect and deserve; however, Consumers Energy is not seeking recovery of the financial portion of the EICP.

The goals are the same for the officer EICP, but the weightings are different. Officers are 30% based on the achievement of operational measures and 70% based on the achievement of financial measures.

II. EMPLOYEE COMPENSATION PHILOSOPHY

Q. What is Consumer Energy's philosophy about the overall level of compensation?

A. The Company's management believes Consumers Energy should pay a fair and reasonable salary, comparable to the market that is equitable to employees, consistent with Company values and strategies, and that supports the highest level of customer service at a reasonable cost.

Q. What are the components of Consumers Energy's compensation for non-officer employees?

A. There are two parts of overall compensation for non-officer employees of Consumers Energy. The first part is base pay or salary. The second part for salaried employees is annual incentive compensation.

Q. What are the components of Consumers Energy's compensation for officers?

A. There are three parts of overall compensation for officers of Consumers Energy. The first two parts are cash compensation through base pay and annual incentive compensation. The third part is equity-based long-term incentive. As I mentioned earlier in my direct testimony, the Company is not seeking recovery for the costs of long-term incentive compensation in its rate recovery request in this case.

Q. Why does the Company make a portion of compensation subject to incentives?

A. A wide body of research supports the view that incentive pay (a variable pay component) works. One researcher states, "theory and research show that incentive pay can substantially increase individual and organizational performance and can represent a powerful tool for establishing a competitive advantage within an industry." (Dow Scott, *Incentive Pay: Creating a Competitive Advantage* – WorldatWork Press, 2007). There are many more cases of incentive plans as an effective motivational tool. Group incentive plans can contribute to organizational collaboration and achievement of company goals which lead to benefits for customers. A May 15, 2018, Forbes article entitled "The Key to an Effective Incentive Plan" (Bill Fotsch and John Case) continues to support this theory indicating:

> Incentive plans, by definition, are supposed to affect people's behavior on the job, day in and day out. They incent people to work harder and smarter, to go the extra mile, to collaborate with their coworkers, to come up with new ideas to improve some aspect of the business.

People don't work for money alone, but they do respond to incentives.

When properly selected and implemented, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal. In addition, incentives increase a company's ability to attract, hire, and retain qualified and motivated individuals. A study by the International Society of Performance Improvement showed that incentive pay programs increase performance by an average of 22.0%. (International Society of Performance Improvement, "Incentives Motivation and Workplace Performance Research and Best Practices," Spring 2002). As stated by the Society of Human Resource Management:

> Research has demonstrated that some human resource programs and initiatives produce a significant impact on performance in organizations (as measured by factors such as quality, productivity, speed, customer satisfaction and unwanted turnover). The two initiatives that consistently showed statistically significant positive results were linking pay to performance and using variable pay. Research has established the potential of variable pay to produce the desired business results. [Robert Greene, "Variable Pay: How to Manage it Effectively, Society of Human Resource Management," April 2003.]

Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers. High-level qualitative customer benefits are listed later in my testimony. Company witness Ashley E. Meschke's testimony illustrates the quantitative benefits to customers.

Q. Are the overall compensation levels for employees subject to the non-officer EICP reasonable?

A. Yes. Overall compensation levels for employees subject to the non-officer EICP and management's decision of how to allocate the overall compensation between base salary and EICP are reasonable. As stated later in my testimony, it is common practice for companies to have a variable pay (i.e. EICP) component of total competitive compensation levels.

Q. How does Consumers Energy determine what level of overall compensation for non-officers is reasonable?

A. First, Consumers Energy's management targets compensation to the market median. Second, Consumers Energy's management actively reviews compensation levels so that employees are neither overpaid nor underpaid relative to the market. Third, the Company uses a rigorous survey process which uses valid and reliable data from multiple third-party sources to determine median levels of compensation. Forth, the Company reviews incentive compensation levels from third-party data sources to determine the target level of compensation. The fact that a portion of the compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. To the contrary, removing the incentive from employees' compensation package or failing to meet incentive performance goals, would render their compensation below-market.

Q. Would it be reasonable for Consumers Energy to pay employees below market level on an ongoing basis?

A. No.

Q. Why would it be unreasonable for Consumers Energy to pay below market level?

A. Consumers Energy has a responsibility to customers to employ a competent workforce that is ready, willing, and best able to provide service for its customers. Paying competitive wages and salaries is necessary to fulfill that commitment. It would not be reasonable or fair to the Company, its employees, or customers for the MPSC to set rates at a level that did not include reasonable levels of overall market-based compensation.

The level of service that customers deserve requires a qualified, experienced, and motivated workforce. The Company can attract, retain, and motivate talented employees when its overall compensation is competitive with market levels. A decision to compensate employees below market levels would detract from the Company's ability to assemble the committed and customer-focused workforce that customers deserve. Over time, this would be detrimental to customers, as well as being unreasonable to the Company's diligent, hardworking employees. Compensating employees below market levels will eventually result in their leaving for jobs that are paying at market levels. Over time, the workforce would tend to be less qualified, less experienced, less productive, and less capable of serving customers (as the most capable would, in general, tend to go to employers paying at competitive levels). This, in turn, could lead to less efficiency and could result in a need to hire more employees to produce the same service to customers, thus increasing costs to customers.

Q. How does the Company determine the level of compensation for salaried non-officer employees?

A. For salaried non-officer employees, the Company uses salary survey data from utility and energy companies. Using this survey data, a benchmarking analysis of base pay and incentive pay is made between the Company's jobs and comparable survey jobs. Benchmarking analysis is a comparison of jobs commonly found in the labor marketplace and/or a job that is highly relevant/populated within a company. This comparison indicates where the Company's pay stands relative to the market. The Company's goal is to target base pay levels within plus or minus 5.0% of the market median for non-officers. While pay for individuals inevitably varies from the survey market levels due to differences in experience levels, education, job performance, longevity, position responsibilities, etc., the survey data indicate that the Company's overall non-officer compensation levels, assuming the EICP payment at the target level, are on average within target pay level of plus or minus 5.0% of market median. Exhibit A-40 (AMC-2) provides a summary of average exempt and non-exempt base pay for Company benchmark jobs compared to market using 2023 data for 2024 pay structure purposes.

Paying compensation that approximates the market median is particularly important given that Consumers Energy will continue to experience significant attrition (current employees eligible for retirement is 17% of the workforce) and have a need over the next few years to hire engineers, information technology, and other personnel to staff various projects and serve customers. Competitive pay is necessary to retain the talent needed to deliver on the Company's Integrated Resource Plan ("IRP"). In competing for engineers, as well as other personnel that are skilled, high-performing customer-focused candidates, it will be important to have a reputation for paying a competitive level of overall compensation. Excluding the incentive target amounts would result in the Company's pay levels being as much as or greater than 10.0% below market level.

Q. How do you know the market data that the Company is using are appropriate and are not inflating salary levels?

A. The Company uses several third-party survey sources to compare to the non-officer salaried workforce. The Company participates in and uses an industry survey performed by Willis Towers Watson, Aon, and Mercer LLC ("Mercer"), which are well-respected, independent third-party compensation experts. These surveys are conducted by surveying companies which report data on an anonymous basis. When using the survey data, the Company looks at the base pay and incentive reported for highly populated jobs for which there is a comparable job match. In this way, the Company is matching the relevant market, not trying to lead the market, and thus not inflating its overall compensation above prevailing market levels. By using multiple independent survey sources, the Company can determine if any one source is varying significantly from another.

Q. Can you give an example of the relationship between the Company's base pay levels and the market's pay levels?

A. See Exhibit A-40 (AMC-2) for a summary of average exempt and non-exempt base pay for Company benchmark jobs.

Q. Are incentive plans common in the utility industry?

A. Yes, incentive plans are quite common. Annual incentive programs are a critical and highly integral part of competitive compensation packages for many organizations. Research from Willis Towers Watson's 2012 Survey Report indicates that approximately 80.0% of companies offer annual incentive (variable pay) programs. That number is slightly higher at 81.2% for those companies within the utility industry sector. The survey data supports the conclusions that including incentive pay as part of a competitive pay package is a standard industry practice and is required to attract and retain good employees.

Research from Mercer's 2014/2015 U.S. Compensation Planning Survey Report indicates that approximately 83.0% of companies offer annual incentive (variable pay) programs. For companies within the utility industry sector, the survey indicated that

98.0% of executives, 99.0% of management, 94.0% of non-sales professionals, and 86.0% of clerical and technicians were eligible for an annual incentive.

A 2012 Mercer study of more than 1,200 organizations reveals that actual company spending on variable pay for salaried exempt employees, as a percentage of pay, is 12.0% and salaried/hourly non-exempt employees, as a percentage of pay, is 6.0% to 7.0% for energy companies. A 2009 Hewitt Associates study of more than 1,100 organizations further reports that companies were budgeting variable pay for salaried exempt employees at 11.8%, and 5.5% to 6.1% for salaried/hourly non-exempt employees, for 2010. Ken Abosch, leader of Hewitt's North American Broad-Based Compensation Consulting business, added:

> Over the past decade, we've seen companies steadily shift from a fixed pay model to one that emphasizes true performance-based awards, and we expect this trend will continue.

Consumers Energy's practice of making a portion of overall employee compensation subject to incentives is consistent with best practices for compensation.

Q. What has been the trend in variable or incentive pay?

A. A 2016 study by Aon Hewitt indicated a 72% growth in variable pay spend over the past 20 years. Variable pay grew from 4.1% of base salaries in 1996 to 12.9% of base salaries in 2015. Business incentive plans are the most prevalent with 77% of companies using this type of variable pay award in 2015 up from 55% in 1996. Business incentive plans refer to plans that are based on Company financial and/or operational goals. According to a 2021 study published by WorldatWork and Compensation Advisory Partners, the vast majority of companies (99%) have short-term incentive programs ("Incentive Pay Practices: Publicly Traded Companies," July 2021, WorldatWork and Compensation

Advisory Partners). Moreover, a 2020 study by Willis Towers Watson on Salary Increases shows that 89% of Energy companies utilized short-term incentive (EICP) compensation programs.

Q. Why is the use of incentive pay such a widespread practice?

A. Incentive pay is the number one design used to influence short- to mid-term business or performance results. Coupled with clear strategy, solid leadership, and good, safe working conditions, variable pay incentive designs:

- Increase employees' understanding of what is important to the Company;
- Increase employees' identification with the Company's success and the factors by which it is measured;
- Reward valued skills and behaviors; and
- Enhance employee engagement by educating them on how and why their contributions will benefit them, the Company, and our customers.

Dividing overall compensation between base salary and incentive compensation is an approach that is common and effective in business today.

Q. How many employees does the Company have that will be eligible for the non-officer EICP payout?

A. Consumers Energy has approximately 4,500 employees (total utility) who are eligible to receive an incentive if, and when, the requirements for a payout are met. The risk of no payout is the same for all these eligible employees. Either every eligible employee receives a payout, or no one receives any incentive compensation.

Q. How did the Company determine the level of compensation that would be provided as incentive compensation for these eligible employees?

A. For the historical test year, the EICP target level for each pay grade was established by reviewing third-party market data on the mix of base salary and at-risk variable pay (EICP), historical rate case relief and amounts that will assist in motivating performance that will result in benefits to customers. The EICP compensation is part of the overall market-based competitive level of compensation, not in addition to it. Beginning in 2024, the EICP target levels are based on career stream and job level established by reviewing third-party market data on the mix of base salary and at-risk variable pay.

Q. Explain if the Company reduced base pay when it started to pay incentive awards in order to obtain market-based pay based on the combination of the two components of pay.

A. The Company has always had a broad-based incentive compensation plan in place for salary grades 19 and above (typically management level). In 2003, an EICP for employees in salary grades 18 and below (typically individual contributors in technical, professional, or support roles) was initiated. Base pay levels were not reduced for these employees at the time the plan was implemented. This was due to the fact that at the time the plan was implemented, total compensation, which is base salary and annual incentive, was slightly below the 50th percentile (median) point of survey results. The Company targets pay levels of plus or minus 5.0% of market median. The Company's pay level, including the additional incentive, continues to be within this range.

Q. Is there an alternative to providing incentive pay for salaried employees?

A. The alternative would be to increase the base compensation to a level that approximates the overall competitive market level of compensation. Absent the higher base pay, Consumers Energy's compensation offering would not be competitive with the labor market. For example, if the base target were $50,000 for a hypothetical job and market-based average pay was $50,000 plus a $2,000 incentive award, then the Company would need to offer $52,000 to match the market's current pay. So, the alternative to having an incentive component of overall compensation would be to raise base pay to the market's overall compensation. Eliminating incentive pay would result in the same compensation costs, but employees would lose focus on continuous improvement, safety, quality, cost, reliability, and delivery to the customer. Increasing base pay would also result in a higher level of fixed costs tied to base pay, such as certain pension and defined contribution benefit plans, life insurance, disability insurance, and other salary-based employee benefits.

The Company's overall compensation needs to be comparable to the market for salaried employees regardless of whether it is composed of only base pay or composed of base pay plus the target incentive award amount. The Company has maintained overall compensation at competitive levels through base pay plus the target incentive award amount.

Q. Would elimination of incentive pay be in the best interests of customers?

A. No. With incentive compensation, the employees and the Company must re-earn the at-risk compensation each year. If high levels of performance are not met each year, incentive pay can be reduced or eliminated. The elimination of variable "at risk" pay would create a situation where all compensation is guaranteed and would remove an important incentive to improve service. This result would be counter to customer interests. The elimination of variable "at risk" pay would create a situation where compensation would be below market competitive levels. Competitive pay is needed to attract and retain the high-quality talent required to deliver exceptional service to customers. It would be difficult to achieve the Company's purpose of world-class performance delivering hometown service without the right talent. The knowledge, skills, and abilities of Consumers Energy's employees are key determinants in the quality and timeliness of service that customers receive. Our ability to deliver what customers expect such as reliable and safe energy delivery, on-time completion of service orders, and energy savings depends upon having the right talent in the right job at the right time. Having incentive compensation that is structured around goals that provide benefits to customers is in the best interest of the customer.

Q. How does the Company determine the level of overall compensation for officers?

A. A utility must maintain a competitive total compensation package to attract and retain executive talent. As discussed above, Consumers Energy creates a compensation package for officers that delivers base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50th percentile of the market, as defined by a Compensation Peer Group approved by the Compensation Committees of the Boards of Directors. The Compensation Peer Group consists of energy companies comparable in business focus and size to CMS Energy with which the Company might compete for executive talent. The Compensation Peer Group currently includes 18 companies.

Q. How do you know the market data that you are using for officer compensation are appropriate and are not inflating salary levels?

A. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of a Compensation Peer Group, which it develops based on criteria discussed below, as well as taking into account additional information from published surveys of compensation in the public utility sector and general industry. During the Compensation Committee's review of officers' compensation levels, consideration is given to the advice and information received from the independent compensation consultant; however, the Compensation Committee is ultimately responsible for determining the form and amount of the compensation programs.

Where available by position, Compensation Peer Group data serves as the primary reference point for pay comparisons of utility specific roles, and broader survey data and published proxy data are also provided by the compensation consultant as a point of reference for utility-specific roles and comparisons of general industry roles. Where available by position, the independent executive compensation consultant of the Compensation Committee, gathers compensation data from Willis Towers Watson's Energy Services Executive Database (over 50 investor-owned utilities) and Willis Towers Watson's General Industry Executive Database (approximately 500 participating companies), which it regresses based on CMS Energy's revenues to provide additional market context to the Compensation Peer Group. In selecting members of the Compensation Peer Group, financial and operational characteristics are considered. The criteria for selection of the Compensation Peer Group included comparable revenue, relevant utility industry group, similar business mix (revenue mix between regulated and non-regulated operations), and availability of compensation and financial performance data.

The survey data indicate that the Company's overall officer compensation levels, assuming the EICP and restricted stock payment at the target market-based level, are reasonable.

In addition, annually, proxy-advisor service companies Glass Lewis & Co. and Institutional Shareholders Services assist institutional investors in their advisory vote on the reasonableness of compensation pay and practices of the proxy-named executive officers by providing a vote recommendation. The incentive pay practices for the proxy-named executive officers are the same as for the remaining officer group. In 2023, both proxy advisory service firms recommended a vote "for" the proxy-named executive officer compensation pay and practices. Also, shareholders voted 97% in favor to approve executive compensation as described in the 2023 Proxy Statement which is above the S&P 500 average of 89%.

Q. Does the independent consultant provide other services for CMS Energy or Consumers Energy that could result in a conflict of interest?

A. No. The independent consultant is required to obtain approval of the Compensation Committee of the Boards of Directors before undertaking any activity on behalf of the management of CMS Energy or Consumers Energy. During the time the consultant has been engaged as the compensation consultant for the Boards of Directors, it has not performed any services on behalf of the management of CMS Energy or Consumers Energy. The independent consultant is hired by and serves the Compensation Committee; it is not hired by or providing services to CMS Energy or Consumers Energy.

Q. Are surveys the only determining measure used in setting officer compensation levels?

A. No. Additionally, the Compensation Committee considers experience levels and individual contributions of the respective officers.

Q. Are incentive plans for officers common in the utility industry or in other industries?

A. Yes, incentive plans are prevalent. Research from Mercer, U.S. Compensation Planning 2014/2015 survey indicates that approximately 96.0% of companies, and 98.0% of energy companies, offer annual incentive (variable pay) programs for officers. The survey data support the conclusions that including incentive pay as part of a competitive pay package is a standard practice and is required to attract and retain qualified officers.

III. INCENTIVE COMPENSATION PLANS

A. Description of Incentive Plans

Q. Please describe the EICP that is in place for 2023.

A. The EICP for 2023 is based on achieving performance goals related to critical areas of the Company's operations. The goals focus on continuous improvement measures and maintaining financial health to deliver value benefits to customers (not seeking recovery of financial goals in this case). The Company's EICP goals seek to encourage employees to provide reliable energy, customer value, and responsive service to customers, and to do so safely. Each year, the Company establishes utility-specific performance criteria which focus on continuous improvement goals and breakthrough goals. For 2023, there were six specific operational performance measures and one measure related to being financially healthy. The EICP Operational Performance Measures are summarized on Exhibit A-39

(AMC-1). The 2023 officers and non-officer goals and weighting are shown on page 1 and operational goal targets on page 2.

Q. Please describe Exhibit A-39 (AMC-1).

A. Exhibit A-39 (AMC-1) identifies the operational performance areas that the EICP focuses on and identifies the specific measures that have been adopted for each of these areas. For the 2023 historical year, 50.0% of the non-officer incentive compensation and 30% of officer incentive compensation was based on operational performance. For purposes of this rate case, the Affordability (O&M savings from Waste Elimination) measure associated cost has been removed from the rate request as the Company has determined that it is financial in nature.

Q. Is the structure of the EICP goals for 2024 similar to 2023?

A. The specific performance measures and targets for 2024 are, as in prior years, a combination of measures related to operational performance and financial performance. As indicated above, the Company is not seeking recovery of the financial performance measures in the case. For non-officers, the operational performance and financial health goals will be weighted equally (50% operational and 50% financial). For officers, the operational performance and financial performance measures are weighted 30% operational and 70% financial. The officer operational goals are the same as the non-officer operational goals.

Q. Is the eligibility for the EICP plan for 2024 and the projected test year similar to 2023?

A. In third quarter 2023, Consumers Energy implemented an updated job architecture. Job architecture encompasses job levels, job titling, pay grades, career paths, spans of control, the criteria for career movement, and equitable compensation programs based on job value. Job architecture serves as the foundation that will help the Company attract and retain the high-quality talent required to deliver service to customers. As a part of implementing the new job architecture, compensation programs such as the EICP were reviewed. This review resulted in the EICP target for non-officers to shift from one based on pay or salary grade to one based on career stream (management, professional, technical, or support) and level (i.e. entry, career, senior, supervisor, manager, director, etc.). With this change, the EICP continues to provide a link to the Company strategy and what is important to delivering safe and reliable energy to customers.

Q. Will the non-officer performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?

A. Yes. Performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. While the number and precise phrasing of operational goals may vary from the historical test year, areas of focus will continue to include safety, reliability, cost, delivery, and customer care.

Q. Will the officer performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?

A. Yes. Operational and financial performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. The operational measures will hold a weighting of 30%, meaning 30% of the officer incentive compensation is based on operational performance (same goals as non-officers) and the remaining 70% is based on financial performance. As noted above, the Company is not seeking recovery of the financial performance measure in this case.

Q. Please discuss the strategy and process for developing the EICP goals.

A. Company witness Meschke provides a discussion of the strategy and process for developing the EICP goals.

Q. Why has the Company's management chosen to design the EICP with broad goals and objectives on a Company-wide basis rather than individual goals and objectives for individual employees?

A. It is necessary and appropriate for a large organization, such as Consumers Energy, to establish broad goals and objectives that are communicated to all employees as matters that are important to the success of the organization. Some employees will be in a better position to influence whether particular goals and objectives are met, but having every employee linked to a set of common customer-focused objectives is an effective method for emphasizing the importance of customer value and service. Having common goals and objectives (i) provides clear communication of Company goals, (ii) encourages employees to support each other and work together for common goals, and (iii) provides a scorecard with a focus on corporate-wide goals that benefit customers.

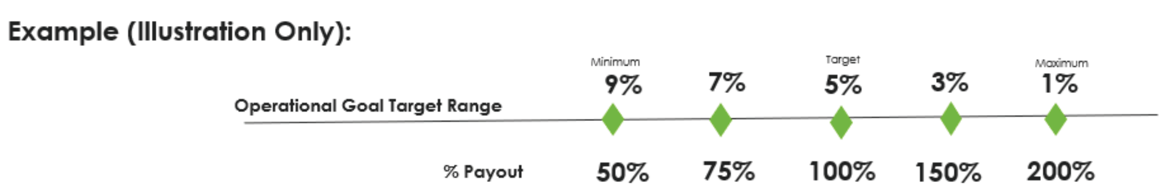
Consumers Energy incorporates individual goals through the annual performance feedback process, which includes the creation and review of individual goals and objectives for each salaried employee and the opportunity to recognize and reward individual performance. The existence of a common set of customer objectives enables supervisors and employees to establish individual goals and objectives which are supportive of, and in alignment with, the corporate goals reflected in the EICP.

Q. How are the payout levels that are shown on Exhibit A-39 (AMC-1) set?

A. When setting payout levels, threshold is set at a level of achievement that can typically be reached 80% to 90% of the time in a 10-year period. Maximum payout is for exceptional performance (10% to 20% of the time in a 10-year period). These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. Overall compensation levels, including the EICP at target (100%) level that Consumers Energy seeks, are not excessive. It is reasonable for Consumers Energy to pay its employees competitive levels of compensation.

Q. Are the payout levels that are shown on Exhibit A-39 (AMC-1) similar to 2023 and the projected test year?

A. Yes, each operational measure will have its own threshold, target, and maximum for payout. This practice aligns better to market practice and with engaging and motivating performance. Gallup research supports substantial and well-established connections between employee engagement and the achievement of outcomes critical to the business and to customers. See illustration of banded goals below:



This structure was in place for 2023 and planned to be in place for the projected test year.

Q. Why are you including both gas and electric performance measures in this plan as this is a gas rate case?

A. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures.

Q. How are the targets for the annual officer EICP incentives measures determined?

A. As mentioned earlier, the goals are the same for the officer and non-officer EICPs, but the weightings are different.

Q. Why is the weighting different for the officer plan?

A. Officer annual incentive awards were based on the achievement of EPS and utility operational goals for the historical test year. As indicated above, the officer plan has a 30% weighting of the same operational goals as non-officers. This strengthens the linkage of officer and non-officer performance while aligning with typical indicators of officer strategy execution through financial goals (weighted at 70%) and corresponding higher weighting.

Q. How are the target amounts for the annual officer incentives determined?

A. The Compensation Committee determines the target amounts of the annual officer incentives. In determining the amount of target incentives, the Compensation Committee considers the following factors:

- The target incentive level and actual incentives paid in recent years;
- The relative importance, in any given year, of each performance goal established; and
- The advice of the Compensation Committee's compensation consultant as to compensation practices at other companies in the Compensation Peer Group and the utility industry.

B. Assessment of Customer Benefits of the Incentive Compensation Plans

Q. What level of expenses for Consumers Energy's incentive plans has been included in the test year revenue requirement?

A. The Company is requesting recovery of gas O&M expenses related to EICP incentive compensation plans at target (100.0%) levels. The following is a listing of the goals illustrated in Exhibit A-40 (AMC-2) for which the Company is requesting recovery:

- **Employee Safety** (OSHA Recordable)
  (Incidents, High Risk Injuries and Zero fatalities)
- **Culture Index**
  (Employee Empowerment, Employee Engagement and DEI)
- **Customer Experience** - Cxi
  (Survey measuring Customer Experience)
- **Electric Reliability** - SAIDI
  (System Average Interruption Duration Index)
- **Methane Emission Reduction**
  (Reduction of Methane Emissions through replacements of Mains and Services, etc.)

The level of expense is approximately $1.5 million as illustrated in Exhibit A-41 (AMC-3).

Q. Please explain Exhibit A-41 (AMC-3), page 2.

A. Exhibit A-41 (AMC-3), page 2, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or a merit increase rate to historical O&M expense. Page 2, column (b), shows the historical O&M expense. Column (c) shows the historical amount that an inflation or labor rate was applied to. Columns (e) and (g) show the amounts to which an inflation rate or labor increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the labor and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i). For purposes of incentive expense, only labor increase is applicable. No inflation rate was applied.

Q. How are the gas expenses of $1.5 million related to annual incentive compensation calculated?

A. The $1.5 million for EICP incentive compensation is based on the following:

- For officers: The rate case expense amount is based on 2023 salaries multiplied by the approved target incentive percentage of salary from the 2023 Compensation & Human Resources Committee of the Board of Directors. Factors that impact the incentive expense year-over-year are retirements of officers and successors being at lower incentive amounts (decrease expense), forecasted salary increases (increase expense), and addition of new officers (increase expense) as indicated below.

- For non-officers: The rate case expense amount is based on an estimate of the number of employees in each career stream and job level multiplied by the plan prescribed incentive target amount. Progression to higher job levels as employees gain additional work experience will increase the amount of incentive expense year-over-year and headcount reductions will decrease the amount of incentive expense year-over-year.

Q. How was the gas portion of the incentive compensation expense determined?

A. The allocation percentages were supplied by the Accounting Department.

Q. Is a portion of the gas incentive compensation expense allocated between O&M and capital?

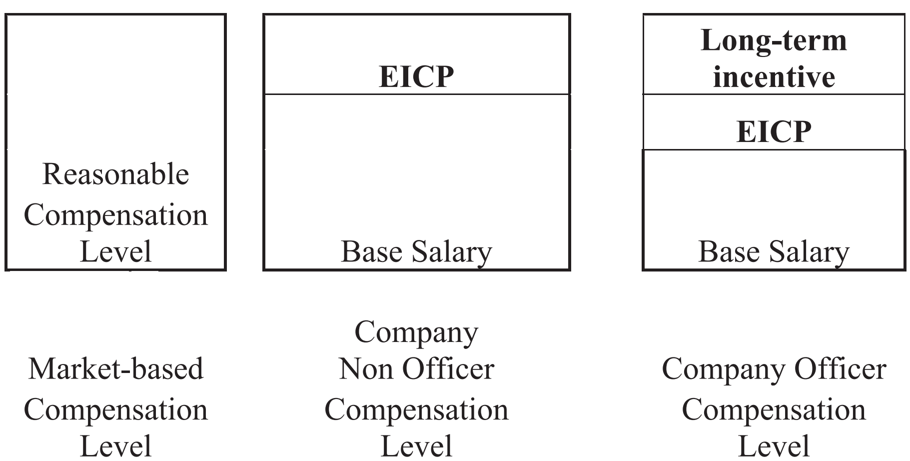
A. Yes. In the Company's 2014 Electric Rate Case, Case No. U-17735, the Commission issued an Order on November 19, 2015, approving the recovery of annual incentive (EICP) in rates for non-officers and non-proxy officers. As a result, in the first quarter of 2016, the Company began classifying annual incentive expense for the approved employee groups as a labor cost. The labor percentages charge between O&M and capital is based on labor studies performed by each business unit for the operational goals portion of the cost. Costs associated with financial performance measures are charged to O&M only.

Q. Do Consumers Energy's gas customers benefit from making a portion of employee compensation subject to incentives?

A. Yes. Paying a competitive level of compensation is an essential prerequisite to being able to attract, retain, and motivate qualified employees. Consumers Energy has determined a reasonable level of compensation and then made a portion of that compensation at risk. Structuring employee compensation so that it includes both base pay and incentive compensation provides motivation for an employee to strive for the total compensation for their position by contributing to the achievement of performance measures. Customers receive both qualitative and quantitative benefits at no additional cost above market-based compensation.

Q. Why do you say there is no additional cost above market-based compensation?

A. The officer and non-officer incentive plans are designed so that the total base salary plus incentive payments will be equivalent to the market-based compensation level. The EICP is part of the overall reasonable level of market-based compensation. It is not in addition to it. This is illustrated in the following diagram:



Q. What is the appropriate standard from a business perspective in evaluating the reasonableness of the EICP costs?

A. Making a portion of compensation subject to incentives is a recognized, well-established, common practice in the utility industry and is reasonable and appropriate. The appropriate standard from a business perspective in evaluating whether the level of compensation is reasonable is whether the *overall* level of compensation, including both base salary and incentive compensation, is reasonable. Using this standard would also be appropriate for ratemaking purposes. Looking at whether the overall level of compensation is reasonable will provide a better indication of whether the incentive plan results in excess rates than attempting to examine the cost allocable to the incentive compensation compared to benefits to customers. The overall level of compensation that Consumers Energy has included in its request in this case is reasonable.

Q. Under the Company's proposal, do shareholders bear a portion of the EICP costs?

A. Yes. The Company's incentive compensation proposal in this case does result in shareholders bearing a portion of incentive costs. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level and for the financial performance measures' cost. Thus, shareholders will absorb any resulting increase in costs arising from above-target performance and for financial measures. If actual payouts in future years are less than target levels due to under performance, then the Company's shareholders will absorb the consequence of underperformance results along with customers. The Company is allocating to shareholders 100% of the costs of incentive compensation for above-target performance and financial measures.

Q. Is the payment of incentive compensation reasonable given the economic conditions facing the Company's customers?

A. Yes. The incentive compensation costs are reasonable costs of doing business. The market median of survey data reflects current economic conditions and current pay practices. The Company maintains an annual practice of surveying the external market. Any trends in compensation – increases/decreases – would be reflected in the market survey results. Paying a reasonable level of compensation is in the best interests of the Company's customers. Incentive compensation does not result in excessive compensation and is reasonably necessary to attract, retain, and motivate a talented workforce to serve customers. Further, gaps between the skills that employers require and those available in the labor market are growing. Paying a reasonable level of compensation which includes incentive compensation is necessary to attract, retain, and motivate a talented workforce. As of December 2023, the unemployment rate was 4.3% in Michigan and 3.7% nationally, according to the Bureau of Labor Statistics ("BLS"). In addition, BLS data show that there are more job openings in the United States than there are unemployed people. The war for talent is real, and the Company must offer a compelling value proposition to attract and retain the talent required to realize our Company purpose of world-class performance delivering hometown service.

Q. Is the EICP a bonus or profit-sharing plan?

A. No. The EICP is not a bonus or profit-sharing plan. A bonus is a discretionary payment given without predetermined goals or objectives and a profit-sharing plan entitles employees to a share of the profits of the Company without pre-determined goals or objectives and is not part of total cash compensation market levels. Consumers Energy offers incentive compensation, which is based on predetermined goals and objectives and award levels. Incentive compensation is part of an employee's overall compensation and not in addition to it, like a bonus or profit-sharing plan. The fact that a portion of compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. Employee compensation is a reasonable cost of doing business. If overall compensation levels are reasonable, then those costs should be recoverable through utility rates.

Q. What are some of the ways the EICP incentives benefit customers?

A. Customers derive benefits by having a portion of compensation shifted to the EICP Program since the goals of the program are in the interests of customers. Customer benefits are achieved without any additional cost to customers since this program has been structured as a "carve out" of the employee's base salary. If the EICP costs had not been allocated to incentive compensation, those costs would need to be recovered as base compensation for Consumers Energy to have a reasonable competitive level of compensation.

Also, customers are best served when Consumers Energy can attract, retain, and motivate talented salaried employees and executives with compensation packages that are competitive and fair. Performance-based incentives (like Consumers Energy's) permit the Company to provide an incentive to accomplish specific annual goals that represent performance priorities for Consumers Energy and its customers. With variable pay, the employee and the Company must re-earn the incentive award every year. If performance goals are not achieved, cash compensation is reduced or eliminated. Variable pay creates a performance culture rather than an entitlement culture.

In addition, an incentive program structured to focus employee attention on operational performance results in both qualitative and quantitative customer benefits. Among other things, customers benefit from increased cyber security, reliability, and on-time delivery and the focus on employee and public safety that helps reduce potential increased costs.

A quantitative analysis of the benefits received by the customer as a result of the EICP is discussed by Company witness Meschke in her direct testimony in this case.

Q. Has Consumers Energy assessed whether benefits to customers of this program equal or exceed costs?

A. Yes. The performance measures provide appreciable benefits to customers. The costs of the EICP are projected at approximately $1.5 million for the test year. The quantifiable gas benefits illustrated in Company witness Meschke's direct testimony are $3.6 million, which shows that the benefits to customers of the Company's EICP Program outweigh the costs of the program. Since this amount is part of the overall level of reasonable compensation, rather than being in addition to it, all benefits to customers are achieved at zero additional cost to customers. Achievement of the Company's EICP goals and objectives result in pay that is competitive with the labor market, not above the market. The EICP costs are not in addition to the reasonable level of compensation, they are part of the reasonable level of market-based compensation. If these amounts are not paid, then overall compensation would be at a level which is below the market level. There is no valid basis to eliminate incentive costs from the cost of service recovered in rates because they are a part of an incentive plan rather than including these costs as part of base pay. As stated before, overall levels of compensation are at levels that are not excessive. Rate recovery of 100.0% should be allowed.

IV. CONCLUSION

Q. Is the Company's overall compensation program, including the customer-focused incentive, reasonable?

A. Yes. The approach used by the Company is a reasonable approach, is consistent with industry standards, and represents well-established best practices for creating customer focus through compensation design, and it does so without any additional customer cost above the market. The overall compensation levels are reasonable relative to the market, are determined in a reasonable manner, and are a reasonable cost of doing business. Compensation is structured in a manner that rewards improved operational and financial performance that benefits customers. The incentive compensation costs should, therefore, be included in the cost of service recovered from customers. These are legitimate and reasonable costs of doing business. Rates established in this rate case should include approximately $1.5 million for incentive compensation expense.

Q. Please summarize reasons why full recovery of incentive compensation costs should be allowed in this case.

A. Reasons that full recovery of operational goal incentive compensation costs should be allowed include the following:

- Employee compensation is a reasonable cost of doing business, has been set at a reasonable level, and has been determined using a reasonable methodology;
- The amount of compensation that is subject to incentive measurements is part of the market-based compensation level, not in addition to it;

- The incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce to best serve the customer;
- Making a portion of compensation subject to incentives is a recognized, well-established, and common industry practice and is neither irrational nor unreasonable;
- The decision of Consumers Energy to allocate a portion of overall compensation that would otherwise have been in base pay so that it is subject to incentives does not provide a valid basis to disallow these expenses;
- The plan incorporates operational as well as financial performance goals;
- Quantitative and qualitative customer benefits of having a portion of compensation subject to incentives occur at no additional cost above market-based compensation to customers given the compensation structure adopted;
- Investors, including shareholders, bear the expense of incentive compensation in excess of the target levels and for incentive compensation provided to proxy officers; and
- The focus should be on whether the overall level of compensation is reasonable, not on the precise structure of the compensation program.

It is reasonable for Consumers Energy to pay its employees competitive levels of compensation. Paying employees at competitive market levels is reasonable and prudent. Those incentive pay costs are reasonable costs of doing business and are recoverable from customers.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

NEAL P. DREISIG

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Neal P. Dreisig, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am the Executive Director of Gas Strategy in the Gas Engineering and Supply organization, a position I have held since July 2024.

Q. What are your responsibilities as Executive Director of Gas Strategy?

A. As Executive Director, I am responsible to lead the overall long term strategy of the regulated gas business at the Company. This includes long term plans for transmission, storage, compression, distribution, and decarbonization. This also includes the development, recommendation, and administration of the Natural Gas Delivery Plan ("NGDP").

Q. What is your educational background?

A. I graduated from the Michigan State University with a Bachelor of Science in Construction Management in 2006. Additionally, in 2019, I earned a Master of Science degree in Management with a concentration in Finance from Colorado State University.

Q. Do you have any professional certifications?

A. Yes, I have received a Project Management Professional certification from the Project Management Institute in 2011.

Q. What is your work experience?

A. In addition to my current role, I previously held the position of Senior Strategy Manager, responsible for the cross-functional research, analysis, and oversight of decarbonization related assets. I previously held the Manager of Cost Engineering position in the Enterprise Project Management Department for three years. In that role, I had responsibility for the financial predictability of capital forecasting, estimate refinement, and spending efficiency, approximately $1 billion in capital, annually. I have also served the Company as a cost engineer and generation outage planner. In these roles, I assisted in capital project development, planning, and predictable execution. Prior to this, I worked as a construction engineer on large industrial and automotive projects.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have previously provided testimony in Case No. U-20893, the Company's Investment Recovery Mechanism Reconciliation; in Case No. U-21141, the Company's Voluntary Carbon Offset Program; Case No. U-21148, the Company's General Gas Rate Case; Case No. U-21308, the Company's General Gas Rate Case; and in Case No. U-21490, the Company's General Gas Rate Case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide an overview of the Company's natural gas transmission, distribution, storage, and compression systems, and an updated version of the Company's 10-year plan called the *Natural Gas Delivery Plan* per Exhibit A-42 (NPD-1).

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-42 (NPD-1)	Natural Gas Delivery Plan

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. What is the purpose of the NGDP?

A. The NGDP was developed to provide a transparent investment plan for the next decade for the Company's natural gas assets. This investment plan framework considers safe and reliable gas supply, how the Company plans to evolve its assets in accordance with the Gas Pipeline industry standard American Petroleum Institute Recommended Practice 1173 Pipeline Safety Management Systems framework, and to develop a strategic framework in response to decarbonization goals of the Company's natural gas customers and future carbon policy relevant to the utility. The Company's most recent update to the NGDP is included in this rate case as Exhibit A-42 (NPD-1). Over the last five years, Consumers Energy has prudently invested over $4.7 billion in its gas system for safety, reliability, deliverability, system integrity, and customer service through the NGDP.

Q. Can you describe Consumers Energy's natural gas system?

A. Yes. Consumers Energy's natural gas system contains 2,342 miles of transmission pipelines, more than 28,368 miles of distribution mains, and approximately 1.8 million services. The Company operates seven compressor stations on the transmission system, one compressor station on the distribution system, and has 15 underground storage fields. Consumers Energy receives natural gas supply into its transmission system with varying maximum allowable operating pressures. Consumers Energy's transmission system provides reliable supply to its customers by using compressor stations to bring natural gas onto its transmission system and to leverage storage to balance supply with customer demand. The transmission system supplies natural gas to city gates, which deliver gas to the distribution system. The Company's distribution system moves gas from city gates through pressure regulation stations into neighborhoods and commercial and industrial districts to customer homes and businesses.

Q. Were there external drivers considered by the Company that shape the NGDP?

A. Yes. The main external drivers that inform the NGDP are the following:

1. **Safety** – Employees, customers, and the public must safely co-exist with natural gas assets. The Company must anticipate risks and mitigate them proactively.

2. **Increasing Regulation** – Major incidents across the nation's natural gas infrastructure and changing policies regarding carbon and methane emissions continue to introduce new requirements at the state and federal levels.

3. **Changing Supply and Demand Patterns** – NGDP proactively manages natural gas supply to mitigate price volatility while ensuring current and future demand is met.

4. **Environmental Focus** – The natural gas system can contribute greenhouse gas emissions to the atmosphere in the form of carbon dioxide and methane emissions. Customers, regulators, and policymakers at the State and Federal level have expressed interest in how the Company will reduce emissions and how the Company can help customers reduce emissions.

Q. What are the main objectives for the NGDP?

A. The NGDP has four main objectives. These are:

1. **Safe** – Safety remains Consumers Energy's top priority seeking to reduce the probability of incidents that could adversely affect public safety, customers, and employees. This means:

   - Continuously reducing system risk;

   - Modernizing distribution and transmission assets through inspection and replacement of vintage materials in mains and services. Examples of this include vintage main replacements, vintage service replacements, pipeline integrity, Well Logging and Rehabilitation Program, and TED-I projects; and

   - Emphasizing implementation of best practices in Gas Safety Management Systems and records management, and continued use of operational metrics to measure the safety of the Company's personnel, physical and digital assets, and processes.

2. **Reliable** – Consumers Energy is committed to a reliable and resilient system, measured through metrics such as gas flow deliverability to avoid unplanned outages. Consumers Energy views resiliency as the gas system's ability to prevent, withstand, adapt to, and quickly recover from a high-impact, low-likelihood event and essential for safe and continuous customer service. The Company continues to evaluate the balance between system reliability, resilience, and optimization by improving asset reliability.

3. **Affordable** – Consumers Energy's planned system investments including those in technology and automation improve safety and reliability, which can be made while maintaining stable, predictable, and reasonable growth in total bills. These investments will are a small percentage of household spending and provide a highly valuable product that is safe, reliable, and improves quality of life.

4. **Clean** – The Company is committed to reducing greenhouse gas emissions across its systems associated with the energy consumption of its customers. In support of Michigan's MI Healthy Climate Plan along with Federal executive orders and policies, Consumers Energy continues to lead Michigan's clean energy transformation to help customers and suppliers reduce their greenhouse gas emissions. The Company is executing on this commitment in the following key actions:

    - **Reducing Fugitive Emissions**: In 2019, the Company committed to reducing methane emissions from the natural gas delivery system by 80% by 2030;

    - **Customer Programs**: In 2024, the Company received approval for a voluntary program for natural gas customers to offset carbon emissions associated with natural gas use through renewable natural gas. Accordingly, renewable natural gas projects will accompany Michigan forest preservation efforts as part of the MI Clean Air Program.

Please refer to the NGDP, Exhibit A-42 (NPD-1), for further elaboration on the Company's efforts to improve its performance in these areas along with the testimony and exhibits of Company witness Lincoln D. Warriner for distribution capital; Company witness Timothy K. Joyce for compression and storage capital; Company witness Kristine A. Pascarello for material condition distribution capital, advanced methane detection, and engineering operations and maintenance; Company witness Michael P. Griffin for transmission capital and pipeline integrity; and Company witness James P. Pnacek for operating and maintenance expenses for the Company's Gas Operations.

Q. Does the NGDP discuss operational capabilities needed for successful execution of the NGDP?

A. Yes. As Consumers Energy moves forward with the NGDP, there are intentional actions by the Company in the operational capabilities of people, process, and technology for each of the asset areas to enable the 10-year objectives, goals, and outcomes to be successfully achieved. As described in the NGDP, Exhibit A-42 (NPD-1), technology (i.e., information technology) or digital projects enable the expected NGDP future outcomes. Company witness Stacy H. Baker includes in her direct testimony technology projects that are critical in supporting gas functions including gas Supervisory Control and Data Acquisition software, the probabilistic risk model project, and the gas transmission, distribution and compression historians.

Q. Are there any new additions to the NGDP?

A. Yes. The Company included a section associated with energy and environmental justice ("EEJ"). The Company is committed to delivering safe, reliable, clean, and low cost energy to all customers for an equitable future. Recently, the Michigan Public Service Commission and other parties have expressed interest in EEJ. EEJ broadly relates to a holistic view of energy equity, community benefits and impacts on disproportionately impacted communities within the Company's gas service territory. The Company routinely engages communities in its service territory and has a long-standing history of upholding these communities.

Q. How are EEJ communities defined?

A. The MiEJScreen tool, operated by Michigan Department of Environment, Great Lakes, and Energy ("EGLE"), will be used to identify the highest impacted areas within the Company's service territory. Regions with scores of 80+ are defined as EEJ communities. Currently, there are approximately 150,000 customers that reside in EEJ communities within the Company's gas service territory. The Company is seeking to better understand factors including vintage materials and vintage systems in these areas to ensure equitable progress is made in replacing these materials.

Q. Will all of the projects in NGDP support the objectives of Safe, Reliable, Affordable and Clean?

A. Yes. As described in the NGDP, Exhibit A-42 (NPD-1), fully funding both the capital and operating and maintenance costs for the NGDP projects and executing the projects, will position the Company to achieve safe, reliable, predictable, prudent, and affordable outcomes throughout the next 10 years.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

DIRECT TESTIMONY

OF

MATTHEW J. FOSTER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Matthew J. Foster, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am a Principal Rate Analyst for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. Please state your educational background.

A. I graduated from Michigan State University with a Bachelor of Business Administration with a major in finance.

Q. What are your responsibilities in your current position?

A. In my role as a Principal Rate Analyst, I am responsible for the development of Capital and Operations & Maintenance ("O&M") plan targets that align with rate case results.

Q. Please describe your prior work experience.

A. I have held my current position since April 2018. Prior to this role, I held various accounting analyst roles within the finance organization, including in the General Accounting and Property Accounting Departments. In these roles, I have been responsible for property records, depreciation analysis, financial results, accounting entry, analysis, and reporting, including Federal Energy Regulatory Commission ("FERC") and Michigan Public Service Commission ("MPSC" or the "Commission") report filings.

Q. Have you previously testified before the Commission?

A. Yes. I testified in Case Nos. U-21224, U-21308, U-21389, U-21490, and U-21585 which include the Company's most recent natural gas and electric general rate cases.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony is in five parts. In Part 1, I am presenting testimony supporting the test year O&M expense for Corporate Services, uncollectible expense, injuries and damages, and Manufactured Gas Plant ("MGP") direct project management costs. In Part 2, I address the test year capital expenditure for Corporate Services. In Part 3, I address technology projects that support the Corporate Services functions. In Part 4, I am presenting testimony requesting approval for the use of regulatory assets or regulatory liabilities, as needed, by the Defined Benefit ("DB") Pension/Other Post-Employment Benefits ("OPEB") Volatility Mechanism. In Part 5, I am presenting testimony demonstrating Consumers Energy's compliance with the guidelines for intercompany transactions between affiliates as ordered by the Commission.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-43 (MJF-1)	Summary of Projected Gas & Common O&M Expense for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026;
Exhibit A-44 (MJF-2)	Gas Projected Corporate Services O&M Expense for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026;
Exhibit A-45 (MJF-3)	Gas Uncollectible Accounts Expense for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026;
Exhibit A-46 (MJF-4)	Gas Injuries and Damages Expense for the Years 2019 through the 12 Months Ending October 31, 2026;
Exhibit A-47 (MJF-5)	Manufactured Gas Plant Amortization Schedule and Direct

			Project Management Costs 2005 through the 12 Months Ending October 31, 2026;
	Exhibit A-48 (MJF-6)		Organization Chart, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2023; and Purpose of Business, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2023;
	Exhibit A-49 (MJF-7)		Summary of Costs Billed to Affiliated Companies for the Year Ended December 31, 2023; and Summary of Payments Made to Affiliated Companies for the Year Ended December 31, 2023;
	Exhibit A-50 (MJF-8)		Impact on Gas Operations for Costs Billed to Affiliated Companies for the Year Ended December 31, 2023;
	Exhibit A-51 (MJF-9)		Impact on Gas Operations for Payments Made to Affiliated Companies for the Year Ended December 31, 2023;
	Exhibit A-52 (MJF-10)		Affiliated Companies – Rate of Return on Common Equity for the Year Ended December 31, 2023;
	Exhibit A-53 (MJF-11)		2023 Gas Utilities Ranked by A&G per Customer (less Pension and Benefits); and
	Exhibit A-12 (MJF-12)	Schedule B-5.4	Gas Projected Corporate Services Capital Expense for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes, they were.

PART 1 – GAS CORPORATE O&M EXPENSE

Q. Please describe Exhibit A-43 (MJF-1).

A. Exhibit A-43 (MJF-1) summarizes the Company's total 2023 through the 12 months ending October 31, 2026 gas O&M expense for Corporate Services, uncollectible expense, injuries and damages, and MGP direct project management costs. Column (a) of this exhibit provides the O&M expense category, column (b) provides the source references, column (c) provides the 2023 actual O&M, column (d) provides the 2024 O&M projection, column (e) provides the 2025 O&M projection, and column (f) provides the projected test year 12 months ending October 31, 2026 O&M expense. These expense categories are discussed in detail below.

Corporate Services O&M Expense

Q. What areas are included within the Corporate Services O&M expense category, as shown in Exhibit A-43 (MJF-1), line 1?

A. Corporate Services includes those areas common to the administrative functions of a regulated corporation. These include Sustainability and External Affairs; Legal, Ethics, Regulatory and Risk Management; People and Culture ("P&C"), Learning and Development; Finance and Shared Services; General Activities; and administration and other costs.

Q. Please provide a brief overview of the various areas within the Corporate Services area.

A. The areas within Corporate Services include:

- Sustainability & External Affairs – This area acts as a conduit between the Company and its employees, customers, and external stakeholders. The group manages storm communications, promotes safety messaging, advances clean energy programs for the benefit of customers via public media relations and inquiries, advertising, corporate news releases, social media management, and trade association dues and memberships. This area also manages regulatory commission expenses, foundation operations, and community programs. It is responsible for employee diversity and inclusion and strategic talent sourcing;

- Legal, Ethics, Regulatory, and Risk Management – This area includes the Legal Organization, the Corporate Compliance Department, the Corporate Secretary Department, the Securities Law Group, Corporate Information Governance, Risk Management, and it is responsible for determination and management of regulatory filings, and management of the interface between the Company and regulatory staffs. The Corporate Compliance Department is responsible for maintaining a healthy ethical culture, including training on the Company's Code of Conduct and Guide to Ethical Business Behavior, misconduct investigations, and oversight for 40 regulatory compliance areas. The Corporate Secretary Department is responsible for sound corporate governance, including board meetings, shareholder meetings, minutes, shareholder services, and Board of Directors costs. The Securities Law Group is responsible for ensuring full and fair disclosure to investors through compliance with public-company regulatory and legal requirements. Corporate Information Governance is responsible for creating and sustaining a company culture where all employees treat information as an asset, including adherence to the information governance principles: accountability, transparency, integrity, protection, compliance, availability, retention, and disposition. The Risk Management area provides services for corporate insurance programs, surety bonds, and review of commodity and credit risks associated with natural gas, electric fuel, and power purchases. Gas and electric insurance programs include the premiums for property and casualty insurance paid to cover the business including property damage, director and officer's liability insurance, public liability insurance, workers' compensation insurance, fiduciary liability insurance, and fidelity insurance. The Legal Organization is responsible for legal matters involving litigation, credit and collections, environmental, contracts, and other transactions, real property, labor and benefits, business development, and regulatory matters at the state and federal levels;

- P&C and Learning and Development – This area is responsible for creating and executing on the employee experience for all co-workers at Consumers Energy. An engaging employee experience is critical for hiring and retaining the necessary talent to benefit customers and the State of Michigan. The employee experience is comprised of all interactions and services that employees experience during their time with the Company, including recruiting, hiring, training and development, succession planning, compensation, payroll, performance management, workforce relations, employee engagement, and benefits administration. Also included is compliance assurance, which addresses legal and regulatory requirements such as Equal Employment Opportunity, Americans with Disabilities Act, and Family and Medical Leave Act;

- Finance and Shared Services – This area provides the preparation of utility strategic plans, budgets, forecasts, and specialized financial studies. This area also includes the preparation and control of accounting records, including financial statements and reports, and the administration of accounting systems. These systems include budgeting and management reporting, general ledger, accounts payable, fixed assets, and financial and regulatory reporting. The internal audit functions (appraisal of business unit effectiveness of financial controls) and the internal control functions are conducted in this area. The corporate tax function includes all aspects of compliance with federal, state, and local income, sales and use, property, franchise, and excise taxes, book accounting for taxes, tax planning of transactions, tax research, the analysis of tax legislation and regulations, the management and negotiation of tax audits, and tax litigation. Treasury includes all aspects of Company financing and cash management, negotiation of Company credit facilities, treasury operations including initiating cash wire transfer transactions, processing checks for deposit, maintenance of all bank account related activities, borrowing, and investing. In addition, investor relations, rating agency, and investor support are included in the Finance and Shared Services area. Shared Services includes fleet and facilities asset management, corporate safety, and supply chain;

- General Activities – These costs are an aggregation of expenses and credits that are not attributable to any one department but are incurred on behalf of the Company as a whole. Examples include capitalized credits to O&M, billing credits for Administrative and General ("A&G") labor, expenses, and outside services as part of a full-cost loading adder, and senior management time and expenses; and

- Administrative and Other – These costs are primarily for American Gas Association dues and intervenor funding.

Q. How are Corporate Services expenses allocated between the Company's electric and gas businesses?

A. Allocations are developed based upon the type of cost. For example, billing costs are allocated based on customer counts for the electric and gas business, benefits are allocated based on either employee counts or labor, general costs are allocated based on the Three Factor Allocation Method, with other costs being directly charged for identified activities, allocated based on capital and O&M spending levels and special studies.

Q. What is the Three Factor Allocation Method?

A. The Three Factor Allocation Method uses the average of three factors (Operating Revenue, Labor and Property, and Plant and Investments) to allocate costs between the electric and gas businesses.

Q. Explain how the Adjusted Corporate Services O&M was calculated.

A. Exhibit A-44 (MJF-2), line 12, provides the Company's gas portion of total Corporate Services expenses, before adjustments. The 2023 actual O&M expenses were obtained from the Company's records. Specific line-item changes are included as increases or decreases as appropriate to reflect exclusions, remove one-time costs, reflect transfers of costs into or out of the Corporate Services area, or reflect significant ongoing changes in Corporate Services O&M expense. Exhibit A-44 (MJF-2), line 15, column (d), shows the total normalizations of one-time costs from 2023 total Corporate Services expense. The 2023 Voluntary Separation Program costs and One-time Consultant Expenses were removed in the normalizations line. Also, the total of items disallowed by Commission order related to advertising, lobbying, and donation payments were removed on Exhibit A-44 (MJF-2), line 18. Total adjusted Corporate Services expense is found on Exhibit A-44 (MJF-2), line 19.

Q. What is the projected rate of inflation?

A. The assumed rate of inflation is based on the Consumer Price Index ("CPI") which considers factors specific to pricing of goods and services, such as the cost of food, energy, and housing. The CPI is 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026. Consumers Energy uses these inflation rates to project Corporate Services O&M.

Q. What is the source for the CPI?

A. The June 2024 edition of the IHS Markit U.S. Economic Outlook. Company witness Heather L. Rayl supports the inflation rates.

Q. In addition to increases related to inflation, what other specific line-item changes are included to arrive at the test year O&M expense projection?

A. Exhibit A-44 (MJF-2), column (m) includes three line-item changes resulting in a $2,366,000 reduction to the projected test year for organizational efficiencies.

Q. Please describe in detail the specific line item changes included in Exhibit A-44 (MJF-2), column (m) related to efficiencies.

A. Exhibit A-44 (MJF-2), column (m) includes adjustments of ($2,366,000) for labor efficiencies. The reduction of ($2,366,000) to the labor projection is based on an anticipated decrease in headcount as a result of business process optimization initiatives. The labor adjustments were made to four areas included in Corporate Services. Exhibit A-44 (MJF-2), column (m), line 2, includes an adjustment of ($263,000) for Sustainability & External Affairs. Exhibit A-44 (MJF-2), column (m), line 3, includes an adjustment of ($507,000) for Legal, Ethics, Regulatory, and Risk. Exhibit A-44 (MJF-2), column (m), line 4, includes an adjustment of ($505,000) for People & Culture. Exhibit A-44 (MJF-2), column (m), line 5, includes an adjustment of ($1,091,000) for Finance and Shared Services.

Q. Are the costs associated with restricted stock and the Employee Incentive Compensation Program ("EICP") included in the 2023 actuals or projected Corporate Services O&M expense?

A. No. Further details regarding restricted stock and EICP expenses are covered under the direct testimony of Company witness Amy M. Conrad.

Q. Is the level of test year Corporate Services O&M expense reasonable?

A. Yes. The reasonableness of the O&M expense levels is supported by the fact that Standard and Poor's ("S&P") Global Market Intelligence ranked Consumers Energy's 2023 gas A&G costs (excluding pension and benefits) the second lowest out of the 27 top companies ranked on a cost per customer basis for gas utility companies with more than 500,000 customers. The Company's ranking by S&P Global Market Intelligence in this regard indicates the Company's diligence in managing overhead costs. Please refer to Exhibit A-53 (MJF-11) for the report on this ranking.

Q. What is S&P Global Market Intelligence?

A. S&P Global Market Intelligence provides financial and operating data for gas and electric utility companies.

<u>Gas Uncollectible Expense</u>

Q. How did the Company determine the uncollectible expense included in the test year?

A. The Company projects the uncollectible accounts expense for the test year at $15,327,427 as shown on Exhibit A-45 (MJF-3), page 1, column (e). The projected test year uncollectible accounts expense is based on a three-year historical average Bad Debt Loss Ratio ("BDLR") of uncollectible accounts expense to gas service revenue for the years 2021 through 2023, as shown on Exhibit A-45 (MJF-3), page 2. This ratio is applied to the test year gas service revenue, plus energy waste reduction surcharge revenue, to arrive at test year uncollectible accounts expense on Exhibit A-45 (MJF-3), page 1, line 1, column (e).

Q. Does the estimate of test year uncollectible accounts expense consider changing natural gas prices, their impact on customer bills, and the corresponding impact on uncollectible accounts expense?

A. Yes. By using the test year revenues in the calculation, the latest gas commodity cost projections are taken into account.

Q. Does this method provide a reasonable estimate of uncollectible expense?

A. Yes. The Company continuously strives to reduce uncollectible accounts expense. However, year-over-year, uncollectible accounts expense can be impacted by many factors. The economy, the effectiveness of collection practices, funding of low-income assistance programs, extreme weather fluctuations, or any number of other factors that could impact customers' ability to pay. As a result, the Company is proposing a three-year average BDLR from 2021 through 2023 in this rate case filing. This method most effectively captures the recent trends of the many factors that can impact uncollectible accounts expenses.

Q. What mitigation strategies has the Company used to manage uncollectible expense?

A. Over the last several years, the Company has implemented several mitigation strategies serving to reduce uncollectible expense. First, turn on compliance was implemented to stop the cycle of carrying a past-due balance to a newly opened account. Processes were put in place that required customers with an unpaid balance to pay the old balance in full, prior to opening a new utility account. Second, the Company prioritized collection activities on high risk and high volume past due accounts to reduce the overall Company arrears balance. In addition, the implementation of smart meters has helped to reduce uncollectible expense through automated turn-off capability.

Gas Injuries and Damages Expense

Q. Please describe Exhibit A-46 (MJF-4).

A. Exhibit A-46 (MJF-4) summarizes the Company's total 2019 through 2023 actual gas injuries and damages expense and projected injuries and damages expense through the 12 months ending October 31, 2026.

Q. Please describe the costs related to injuries and damages.

A. Gas injuries and damages include liabilities that arise in the normal course of Company business for various types of items such as compensation for damaged trees and crops; restoration of driveways, lawns, and fences; and accidents and lawsuits that are below the various insurance deductibles or are otherwise uninsurable events. Further, workers' compensation costs are included in injuries and damages along with associated internal legal costs.

Q. What expense level is the Company proposing to recover in this case as part of the test year?

A. The Company is proposing that a total of $2,279,205 be included for the test year as shown on Exhibit A-46 (MJF-4), line 4, column (i).

Q. How was this amount determined?

A. The injuries and damages expense is comprised of three components: gas injuries and damages, internal legal costs, and workers' compensation costs. Exhibit A-46 (MJF-4), line 1, reflects the gas property and liability damages. Line 2 represents the amount of internal legal costs that are charged to injuries and damages. Line 3 represents the level of workers' compensation costs for each year. The test year amounts for each of the three components of total injuries and damages expense is based on a five-year average of actual expense for the years 2019 through 2023.

MGP Site Remediation and Direct Project Management Costs

Q. How did the Commission previously address environmental investigation and remediation expenditures at former MGP sites?

A. In Case No. U-10755, the Commission approved deferred accounting for these expenditures, with amortization over 10 years, beginning the year after expenditures are incurred. The approach adopted by the Commission envisioned that prudence reviews would occur in rate cases and that following a prudence review: (i) the amortization expense would be included in rates; and (ii) the deferred balance would be included in rate base and would earn a return at the authorized rate of return. The approach adopted by the Commission also provided for deferred accounting and amortization of third-party recoveries in excess of the costs of recovery over 10 years, the inclusion of the unamortized balance in rate base, and deferred tax accounting. In Case No. U-13000, the Commission upheld this accounting treatment.

Q. Please explain Exhibit A-47 (MJF-5), page 1, line 1, which provides deferred cash expenditures for MGP remediation costs.

A. Line 1 shows deferred cash expenditures for MGP remediation costs for years 2005 through 2023 and projected expenditures through December 31, 2024.

Q. Why are you including projected expenditures through December 31, 2024 and not through the projected test year ending October 31, 2026?

A. I am including projected expenditures through December 31, 2024 to reflect an estimate of actual expenditures that will be available for review by MPSC Staff ("Staff") during this case. Actual expenditures available through the date of Staff's review will be made available at that time.

Q Please explain the remainder of Exhibit A-XX (MJF-5), page 1.

A. Line 2 shows the third-party insurance recoveries for the years 2005 through 2023 and projected recoveries through December 31, 2024. Lines 3 through 22 show the annual amortization of these deferred MGP remediation costs using a 10-year amortization period. Amortization of the third-party recoveries on line 2 is shown on line 22 and acts as a credit to the amortization of expenditures identified in this case. Line 23 is the net MGP amortization expense. It should be noted that until these expenditures are incorporated in a future order, the Company is required to absorb the associated carrying cost and amortization of these costs. Net amortization expense on Exhibit A-47 (MJF-5), page 1, line 23, is included in Exhibit A-13 (HLR-43), Schedule C-6, of Company witness Rayl.

Q. Please explain Exhibit A-47 (MJF-5), page 1, line 24.

A. Line 24 is the project management costs that the Commission provided for recovery as direct costs rather than deferred and amortized costs as part of its Order in Case No. U-14547. The change became effective for the calendar year 2006 onward. These costs are carried forward to line 4 of Exhibit A-43 (MJF-1).

Q. Please explain Exhibit A-47 (MJF-5), page 2, related to the rate base treatment of the MGP unamortized balance.

A. Exhibit A-47 (MJF-5), page 2, provides the net unamortized balance of actual deferred MGP remediation costs and third-party recoveries for the years 2005 through 2023 and projected balances for the year 2024. Column (b) reflects the average unamortized balance to be included in rate base for the test year. Columns (c) and (d) reflect the year-end balances for the 12 months ending October 31, 2025 and 12 months ending October 31, 2026. Column (e) reflects the original costs of the deferred expenditures and third-party recoveries by year.

Q. What ratemaking treatment is the Company proposing in this proceeding for MGP environmental costs?

A. The Company is requesting that the Commission: (i) find that the costs sponsored by Company witness Heather M. Prentice, are reasonable and prudent; (ii) authorize recovery of amortization expense in the amount of $7.3 million as provided on Exhibit A-47 (MJF-5), page 1; (iii) approve test year direct project management costs of $0.9 million as provided on Exhibit A-47 (MJF-5), page 1; and (iv) include the deferred net unamortized balance in the amount of $20.0 million in rate base as provided on Exhibit A-47 (MJF-5), page 2.

PART 2 – GAS CORPORATE SERVICES CAPITAL EXPENDITURE

Q. Please describe Exhibit A-12 (MJF-12), Schedule B-5.4.

A. Exhibit A-12 (MJF-12), Schedule B-5.4, summarizes the Company's total 2023 through the 12 months ending October 31, 2026, gas capital expenditures for Corporate Services. Column (a) of this exhibit provides the description; column (b) provides the 2023 actual capital; column (c) provides the projected 2024 capital; column (d) provides the projected ten months ending October 31, 2025 capital; column (e) provides the projected 22 months ending October 31, 2025 capital; and column (f) provides the projected test year 12 months ending October 31, 2026 capital of $238,000. Categories of expenses include costs to equip and support Corporate Services areas primarily at Company headquarter locations with office furniture and equipment.

Q. Please explain how the projected Corporate Services Capital expense was calculated.

A. The 2023 actual Capital expenses were obtained from the Company's records and subsequent costs were projected using inflation rates.

<u>PART 3 – CORPORATE TECHNOLOGY PROJECTS</u>

Q. Is the Company planning technology projects that support the Corporate Services functions?

A. Yes. Company witness Stacy H. Baker includes, in her direct testimony and exhibits, five technology projects that are critically important in enabling the Company's Corporate Services functions to support the Gas business in a safe, effective, efficient, and compliant manner. These projects are described below:

- The **2025 Union Contract Changes** project requires $105,726 in O&M in the test year.

  Description: The 2025 Union Contract Changes project will implement SAP and other system changes required as a result of three collective bargaining agreements which will be renegotiated and ratified. Collective bargaining agreements expire every five years for Operating Maintenance and Construction ("OM&C"), Virtual Contact Center ("VCC"), and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2025. The VCC agreement ends August 1, 2025. The Zeeland agreement ends October 1, 2025.

  Problem Statement: Collective bargaining agreements expire every five years for OM&C, CCC ("Customer Contact Center") and Zeeland employee groups.

For OM&C, the current agreement ends June 1, 2025. CCC agreement ends in August 1, 2025. Zeeland agreement ends October 1, 2025. Technology changes are required to reflect these new agreements. Otherwise, employees in these union groups may not be paid appropriately or get correct benefits.

Objectives: Completion of this project will provide value to the Company and its customers through: (1) waste elimination by making changes in the software for any pay and benefit changes as required by the new agreements; (2) defect reduction by adding process automation to otherwise manual processes for tracking and recording work, premium, and absence time; and (3) improved employee engagement among the OM&C, CCC, and Zeeland union employees.

Scope: The scope of this project encompasses making any system changes required to support the new working agreement for the OM&C, CCC, and Zeeland employees. Exact details will be finalized after the negotiation process is completed and contracts are approved.

Alternatives: Three alternatives were considered for this project: (1) Make no system changes after the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, union grievances, significant manual processes leading to greater possibility of error, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances. (2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs. (3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievances. Option (3) was chosen because it leverages current SAP technology, automates what would otherwise require manual processing, and is the least costly option.

- The **Expense Reporting Improvements** project requires $123,499 in capital and $43,532 in O&M in the test year.

Description: The Expense Reporting Improvements project will increase productivity when creating expense reports; leverage workflows for expense processing and exceptions; improve adherence to Company policies; provide insights through improved reporting; and minimize human intervention and struggle throughout the expense process.

Problem Statement: Multiple problems exist with our current expense reporting system in the areas of usability, employee engagement, inefficiencies, compliance, and audit exceptions. Submitting expense reports is not intuitive, leading to errors and the need for manual intervention. In addition, employees have to manually scan and attach receipts. All these problems impact employees leading to poor employee engagement scores in regards to simple processes, productivity, and transparency leading to increased costs, inefficiencies, exceptions to policies, and compliance issues. An average of 13% of all expense reports have compliance errors, based on a sample audit of executive assistant submitted expense reports.

Objectives: This project provides value for the Company by: (1) improving expense policy compliance and reducing exceptions, with a target measure of 0 compliance errors; and (2) offering a more user-friendly experience leading to improved employee engagement. Completion of these objectives would enable each employee to save 20 minutes creating an expense report for each of the 50,175 expense reports created in 2021, the Company would have avoided approximately $1.5 million of costs, based on a $90/hr. average rate.

Scope: The project scope includes implementing a new software tool that: (1) provides upfront validation and controls to improve policy compliance; (2) provides electronic document retention for receipts; and (3) integrates corporate credit card data into expense reports.

Alternatives: Three alternatives were considered for the project: (1) continue using the current solution; (2) choose a cloud-based solution with the expense reporting component; and (3) develop a custom front-end. The first alternative would result in waste due to the system not being user-friendly; and does not provide mobile options. The second alternative would introduce new licensing and ongoing maintenance costs; would require periodic upgrades and testing; and would require the SAP Enterprise Portal to be upgraded to integrate with the booking tool. The third alternative and selected option would result in improved user experience and employee engagement as well as mobile capabilities around expense entry.

- The **Talent Management Enablement** project requires $23,095 in capital and $5,950 in O&M in the test year.

Description: The project will deliver technology solutions to enable best-in-class Talent Management programs and processes that are critical to achieve the Company's overarching Talent Strategy Plan. The Talent Strategy Plan is a key enabler of the Company's Integrated Resource Plan (IRP), Electric Distribution Infrastructure Investment Plan (EDIIP), and Natural Gas Delivery Plan (NGDP). Effective Talent Management programs and processes are critical to develop the skills, capabilities, productivity, and experience necessary to successfully execute these plans that deliver clean, reliable, affordable energy through an exceptional customer experience.

Problem Statement: Significant technology improvements are required to transform Human Resources ("HR") to develop the skills and capabilities necessary to achieve the Company's strategic destination. Currently, many Talent Management processes are manually managed with little or no technology enablement. Specifically, the talent compensation processes are mostly manually done outside the system which introduces waste, and a potential for errors. In addition there is a limited visibility of competency gaps within the workforce. The Company cannot effectively place talent in accelerated development programs aligned to competency gaps, nor can it recognize and motivate employees for quickly increasing competency and performance. Furthermore, the Company operates in an increasingly competitive job market where candidates and employees expect best-in-class processes, technologies and experiences relative to their employment and career development. The lack of full technical enablement across Talent Management programs poses a risk to employee attraction, retention and limits the ability to develop the right skills at the right time to deliver on Company strategies.

Objectives: This project will add value to the Company through technology that will enable: (1) fully functional integrated compensation module; (2) accelerated and targeted talent development of critical skills necessary to deliver on the Company's commitment to clean energy and exceptional customer experience; (3) transparency into talent and skill gaps in order to identify retention and service delivery risks within critical areas, as well as inform succession and hiring strategies; (4) improved knowledge transfer, business continuity, and customer service during a time when retirement eligibility is high and risk of knowledge loss has the potential to negatively impact customer service and satisfaction; and (5) increased efficiency and quality of talent management through simplified and automated processes that reduce costs associated with recruiting, onboarding, and developing employees. Talent Management Enablement will deliver the best-practice technology to enable and enhance: (1) Fully functional integrated talent compensation management; (2) Simplified and automated talent management process for employee lifecycle management from on-boarding through off-boarding; (3) Succession Planning and Business Continuity; and (4) Career Development and Employee Retention.

Scope: The scope will include: (1) implementation of each system/application; (2) integration with current systems, applications and processes as applicable; (3) retrofit current systems and applications to ensure a seamless end-to-end experience of HR processes; (4) delivery of mobile capabilities for in scope processes; (5) reporting and analytics dashboards and report insights for in scope processes.

Alternatives: Three alternatives were considered for these Talent Management programs and processes: (1) Develop custom, internally built solutions that could meet most requirements. This alternative was not selected because a custom solution would result in higher overall costs, higher maintenance costs, fewer upgrades, and would not leverage industry best practices to ensure best-in-class delivery. (2) Select an on-premise software tool. This alternative was not selected because it requires internal maintenance, increases infrastructure costs, and would have less frequent upgrades which would hinder the Company's ability to ensure processes are evolving alongside industry trends and best practices. (3) Evaluate and select cloud/SaaS solution(s) which would have lower infrastructure costs, less internal maintenance than an on-premise solution, and would be built and evolved with upgrades based on industry best practices. Based on research, internal experience with successful best practice implementations, and vendor demonstrations, option three was selected.

- The **Enterprise Risk Management** project requires $26,423 in O&M in the test year.

  Problem Statement: The Enterprise Risk Team (ERT) works with Risk Owners (RO) on an annual basis to identify new risks, update existing risks, quantify impacts and likelihoods of these risks, document mitigation plans, identify trends, and formulate risk tolerance metrics. This work is accomplished through an iterative back-and-forth process between ERT and ROs to gain alignment on content. This effort culminates in multiple Risk Map PowerPoint, Microsoft Word and email documents organized by area of risk. These risk maps are then presented to senior management and to the Board of Directors (BoD) on an annual basis. The intensive, time-consuming manual Enterprise Risk Management (ERM) process creates risks of human error that can over or under quantify risks, introduce data anomalies, and create version tracking issues. The existing process results in substantial inefficient use of time by risk analysts and risk owners throughout the Company, limits the breadth of analysis that can be provided, and limits the overall ability of the Company to timely identify, analyze, and communicate risks to our senior leaders, thereby causing potential delays in responding to emerging risks. Because of the lengthy manual process, it is only performed once a year, but must be performed more frequently to proactively manage enterprise risk. Utility industry peers leverage software to more effectively manage enterprise risk management programs.

  Objectives: This project creates value for the Company by: (1) providing real-time risk information to interested parties including the risk team, risk owners, senior management, and the Board of Directors (BoD) supporting proactive risk management; (2) creating a centralized repository for risk identification, management, and mitigation plans; (3) eliminating waste by simplifying processes; and (4) improving efficiency of the risk owners and analysts.

  Scope: The scope of the project includes: (1) create risk analysis templates and tools for automated reporting; (2) configure automated workflow to perform risk updates; (3) configure dynamic templates that prompt the risk owners based on prior selections; (4) organize risk assessments through an online and searchable data capture (repository); (5) create new reports and executive dashboards; (6) data conversion; and (7) set record retention rules.

Alternatives: Alternatives considered include: (1) Continue use of the current manual processes which result in waste, lack of quality results, and annual review of risks; (2) Build a custom internal enterprise risk solution. This option was not selected as it will not result in an enterprise risk program that leverages best practices that exist in software provided by the leaders in risk management software; and (3) Implement a software solution from a leading enterprise risk solution vendor. While this would introduce new license and ongoing support costs, it is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation and insights via the reporting of risk information through management dashboards. In addition, it aligns the Company with utility industry peer practices for more effective enterprise risk management.

- The **Self Service Vendor Portal** project requires $28,248 in capital and $39,811 in O&M in the test year.

Description: The work will create an external portal for vendors to exercise self-service features to streamline and automate purchase order and invoice management and improve visibility to invoice and payment status.

Problem Statement: For Accounts Payable, vendors must repeatedly interact with the Company through multiple channels to ask questions, submit invoices, or check invoice or payment status, including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates, to make payments, or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for vendor invoice and payment management and lacks the ability for vendors to utilize touchless invoice creation from POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 6 contracted resources, and creates the potential for late payments or missing early payment discounts. For Supply Chain, vendors must repeatedly interact with the Company through multiple channels to ask questions, update POs (quantities, costs, shipping dates) including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for updates to the POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 4 employee resources. This also creates the potential for late payments, missing early payment discounts, delays in receiving due to lack of shipping notifications from vendors, delays to scheduled work due to lack of acknowledgement and lead time adherence, and the inability to enforce contractual obligations.

Objectives: This project creates value for the Company by: (1) creating self-service functionality/increasing touchless invoice creation/processing that allows the vendor to select items from a purchase order to create an invoice on demand; (2) providing vendors with real-time invoice and payment status, increasing employee productivity by eliminating waste (3) allow self-service updates of vendor master data (banking info, remittance info, etc.) (4) fewer late payments by vendors thus reducing Company follow up and tracking; (5) creating better visibility for vendors to take advantage of early payment discounts thus reducing related vendor inquiries; (6) reducing vendor questions related to invoice and purchase orders through self-service functions and portal information; (7) reducing the cost per invoice; (8) creating self-service functionality/increasing touchless PO creation/processing that allows the vendor to select items from a purchase order to update quantities, costs, and shipping dates; (9) providing vendors with real-time PO information, increasing employee productivity by eliminating waste; and (10) fewer late deliveries by vendors thus reducing Company follow up and tracking.

Scope: The project scope includes: (1) submit an RFP for a vendor portal solution and implementation; (2) configure ability for vendors to more efficiently and more accurately self-submit invoices and POs electronically; (3) configure ability for vendors to self-convert items on a purchase order to an invoice; (4) configure ability for vendors to view invoice and payment status; (5) configure ability for vendors to make changes to SAP master data, including PO line item details; (6) configure ability to offer/process dynamic discounting (7) create new reports and dashboards; (8) enabling method to validate vendors should have access to the portal and removing access when appropriate; (9) configure ability for vendors to make self-serve changes to shipping status and delivery dates; and (10) integration to vendor invoice management system and SAP.

Alternatives: Alternatives considered include: (1) Continue use of the current manual processes which results in waste and inefficiencies for employees and vendors. This could also result in late payments and lost discounts for vendors; (2) Build a custom solution. This option was not selected as the Company has a vendor portal, that is only leveraged for vendors to ask questions. As well, it doesn't leverage best practices; (3) Building a combination of custom and standard integration to existing solutions. This option was not selected because it doesn't follow industry best practices; (4) expand our current vendor portal. This option was not chosen due to limited functionality and not matching capability roadmaps; and (5) implement a new SaaS solution specific to a vendor portal experience. Option (5) is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation to vendors via real-time processing.

PART 4 – ACCOUNTING REQUESTS

DB Pension/OPEB Volatility Mechanism

Q. Does the implementation of the DB Pension/OPEB Volatility Mechanism, discussed in Company witness Kendra K. Grob's direct testimony, require any specific accounting approvals?

A. Yes. The mechanism would result in deferred debits or credits until balances are fully amortized over 10 years. The Company requests approval to continue recognizing regulatory assets or liabilities as needed to record these deferred amounts as approved in the settlement agreement in Gas Rate Case No. U-21308.

Q. Does the anticipated Leak Detection and Repair Regulations ("LDAR"), discussed in the direct testimony of Company witnesses James P. Pnacek and Kristine A. Pascarello, require any specific accounting approvals?

A. Yes. The requested deferral of O&M expense and the revenue requirement of capital spending associated with LDAR costs above amounts included in rates could result in the recording of deferred debits.

Q. Does the volatility in staking program demand, discussed in Company witness Pnacek's direct testimony, require any specific accounting approvals?

A. Yes. The mechanism would result in deferred debits or credits for test year O&M as discussed on page 48 of Company witness Pnacek's direct testimony.

PART 5 – AFFILIATED COMPANY TRANSACTIONS

Q. What is the purpose of your direct testimony with respect to Affiliated Company Transactions?

A. I am sponsoring Exhibits A-48 (MJF-6), A-49 (MJF-7), and A-50 (MJF-8) to comply with the filing requirements for gas rate cases before the Commission, as clarified in Case No. U-10039. I am also sponsoring two additional exhibits, Exhibits A-51 (MJF-9) and A-52 (MJF-10), as described below.

Q. Please explain Exhibit A-48 (MJF-6).

A. Page 1 of this exhibit provides an organizational chart showing the interrelationship of the affiliated companies that had transactions with Consumers Energy relative to providing/receiving services or commodities. In addition, pages 2 and 3 list their affiliation, percentage ownership, and purpose of business.

Q. Please explain Exhibit A-49 (MJF-7).

A. This exhibit summarizes costs billed to affiliated companies, page 1, and payments made to affiliated companies, page 2, for the year 2023.

Costs Billed to Affiliated Companies

Q. For the costs billed to affiliated companies, how are the costs classified and how are they priced?

A. These costs are classified as to whether they impact the balance sheet, other operating income, or utility operating income. These costs are all priced on a full-cost basis.

Q. What is meant by "costs are all priced on a full-cost basis"?

A. The full-cost basis means total direct costs along with applicable overheads. For services provided, it would be primarily labor costs incurred along with allocated overheads and employee benefits. For commodities purchased, it would be the contracted amount for the commodity based on a negotiated purchase by the Gas Supply organization or, on the electric side, the Electric Supply organization. Property leased is priced per contract.

Q. For commodity purchases, what is the difference between the full-cost amount and market amount?

A. At the time of the purchase, the full-cost amount and market amount would be the same. In other words, it is the agreed upon price between the purchaser and seller of the commodity.

Q. Please describe the types of services performed by Consumers Energy for affiliated companies.

A. Most services performed are administrative services such as payroll, corporate communications, human resources, and computer services; employee benefits related to health care, life insurance, and savings plan; or professional services such as engineering, accounting, legal, and tax.

Q. What types of billing activity are directly classified to the balance sheet?

A. These are the direct costs incurred for employee benefits or for rendering services to affiliated companies that are separately accounted for in Consumers Energy's accounting system and translate to an individualized receivable from the associated company (Account 146).

Q. What types of billing activity are classified as other operating income?

A. Billing activity classified as other operating income consists of income related to the cost of money.

Q. Please explain the cost of money.

A. The cost of money is the recovery of Consumers Energy's cost for the use of its funds expended to render services prior to reimbursement. This recovery is recorded in Account 419, Interest Income.

Q. What types of billing activity are classified as utility operating income?

A. Billing activity classified as utility operating income consists of overhead costs. These costs affect A&G expenses and revenue accounts.

Q. What is the impact of this utility operating income activity on gas operations?

A. As shown on Exhibit A-50 (MJF-8), gas operations were favorably impacted by $587,986.

<u>Payments Made to Affiliated Companies</u>

Q. Please describe the types of goods provided by affiliates and services performed for Consumers Energy as shown on Exhibit A-49 (MJF-7), page 2.

A. Services provided include officer services and professional services, such as accounting, engineering, finance, legal, energy purchases, and tax.

Q. For payments made to affiliated companies, how are they classified and how are they priced?

A. These payments are classified as to whether they impact the balance sheet, other operating income, or utility operating income. These payments are priced on a full-cost basis.

Q. What types of payment activity are classified as balance sheet items?

A. The payments classified as balance sheet items consist of costs deferred on the balance sheet for subsequent reclassification, amounts to be billed, or amounts recorded as liabilities.

Q. What types of payments are classified as utility and other operating income?

A. Payments consist generally of CMS Energy Corporation costs for restricted stock, energy purchases, and professional services.

Q. Is the Massachusetts Formula method used to allocate administrative costs of the parent company to Consumers Energy?

A. Yes. The Massachusetts Formula is used to allocate certain parent company indirect costs to its subsidiaries, which includes Consumers Energy.

Q. Why is the Massachusetts Formula method used to allocate costs?

A. This method is used to allocate indirect costs that cannot be readily identified to any particular subsidiary or affiliated company.

Q. How long has the Massachusetts Formula been used to allocate costs?

A. This allocation method has been used to allocate costs within CMS Energy Corporation since 1987.

Q. Are parent company costs that can be identified to Consumers Energy charged directly to Consumers Energy?

A. Yes. When the costs can be specifically attributed to Consumers Energy, these costs are charged directly to Consumers Energy.

Q. Why is the Massachusetts Formula method an appropriate allocation method for certain Company costs?

A. This method provides a practical means to allocate a pool of common costs based on an equitable and consistent basis. Subjectivity and inability to directly charge costs is the reason the Massachusetts Formula is utilized by entities to allocate costs.

Q. Did Consumers Energy develop the Massachusetts Formula?

A. No. It was first conceived as a method for state tax administration in Massachusetts. Subsequently, the formula was adopted for allocating A&G expense in diversified corporations.

Q. Has FERC approved the use of the Massachusetts Formula?

A. Yes. Examples of specific companies that have used this method include: Duke Energy, Entergy Services, Inc., San Diego Gas & Electric, and Williams Natural Gas Company.

Q. What is the impact of payments classified as utility operating income on gas operations?

A. The amount of payments applicable to gas operations for these activities in 2023 is $3,174 as shown on Exhibit A-51 (MJF-9).

Q. Please explain Exhibit A-52 (MJF-10).

A. This exhibit shows the rate of return on common equity for the affiliates doing business with Consumers Energy.

Q. Is Consumers Energy in compliance with the guidelines for intercompany transactions between affiliates as ordered by the Commission in Case No. U-18361?

A. To the best of my knowledge, Consumers Energy is in compliance with these guidelines.

Q. Does this conclude your direct testimony?

A. Yes.

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 for other relief.	)))))	Case No. U-21806

DIRECT TESTIMONY

OF

SAMUEL M. GELLER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

INTRODUCTION

Q. Please state your name and business address.

A. My name is Samuel M. Geller, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Rate Analyst in Regulatory Policy and Research.

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in American Cultural Studies in May 2009 from Bates College as well as a Master of Public Policy from the Gerald R. Ford School at the University of Michigan in December 2017.

Q. What is your professional experience?

A. After earning my Bachelor's degree, I worked in the nonprofit sector and served as a finance staff member on political campaigns for US Congress, Governor, and City Council. During my graduate education, I served as a Co-Op Student with the Corporate and Government Affairs team at DTE Energy in Detroit which served as my introduction to the utility industry. From 2018 to 2021, I worked for the city of Detroit Mayor's office first as a Project Manager and Analytics Specialist and later as a Capital Budget Analyst. In these roles, I provided policy, data, and financial analysis to lead process improvement projects across city divisions to support vital city services. In September 2021, I joined Consumers Energy as a Senior Business Support Analyst in Electric Distribution Strategy and moved to the Cost Analysis and Pricing section as a Principal Rates Analyst in January 2024. In October 2024, I transferred to the Regulatory Policy and Research section.

Q. What are your responsibilities as Principal Rates Analyst?

A. In my current role with the Regulatory Policy and Research section, I provide analysis, strategic guidance, and technical support for regulatory filings, reports, and emergent issues. As a Principal Rates Analyst in the Cost Analysis and Pricing section, I was responsible for maintaining the electric and natural gas rate design models and sponsoring rate design financial studies, testimony, and exhibits in filings with the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you previously filed testimony with the MPSC?

A. Yes. I have filed testimony in the following case:

Case No. U-21557	Consumers Energy's 2023 Energy Waste Reduction ("EWR") Reconciliation.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to present the Company's gas Cost-of-Service Study ("COSS") for the 12-month period ending October 31, 2026 ("test year").

Q. Is the Company proposing any changes to the COSS methodologies previously approved by the Commission?

A. Yes. Because the Company is proposing changes to the COSS methodologies approved by the Commission in prior cases, in accordance with the Commission's rate case filing requirements established in Case No. U-18238, the Company is sponsoring two versions of the COSS. The first COSS (Version 1) employs the methodologies previously adopted by the Commission in Case No. U-20650 updated for the financial information and supporting data sponsored by other witnesses in this case. The second COSS (Version 2) starts with the Version 1 COSS and incorporates three Company proposals that are responsive to issues or topics raised in Case No. U-21490. The Company is proposing to:

(1) remove Asset Retirement Costs ("ARC" or the Asset Retirement Obligation "ARO") from the calculation of other distribution plant; (2) break out and allocate other distribution plant by Federal Energy Regulatory Commission ("FERC") account; and (3) breakout and separately allocate Customer Care Center ("CCC") and the Business Customer Care ("BCC") expenses. The Company's proposal to breakout other distribution plant by FERC account complies with the settlement agreement in Case No. U-21490.

In addition to COSS Version 1 and COSS Version 2, the Company is presenting an additional COSS for informational purposes as agreed upon in the Company's settlement agreement in Case No. U-21490. This additional COSS replaces Average & Peak ("A&P") methods with Average & Excess ("A&E") as proposed by the Association of Businesses Advocating Tariff Equity ("ABATE") in Case No. U-21490. The Company is not advocating that the Commission adopt this method in its final COSS in this case but recommends adoption of COSS Version 2 for setting rates in this case.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-16 (SMG-1) Schedule F-1	Gas Cost-of-Service Study – Version 1 - Projected 12 Month Period: November 2025 – October 2026;
Exhibit A-16 (SMG-2) Schedule F-1.1	Gas Cost-of-Service Study – Version 2 - Projected 12 Month Period: November 2025 – October 2026;
Exhibit A-54 (SMG-3)	Gas Cost-of-Service Study – Average & Excess;
Exhibit A-55 (SMG-4)	Gas Cost-of-Service Study – Allocation of Home Products Credit;

Exhibit A-56 (SMG-5)	Gas Cost-of-Service Study – ABATE Witness Jonathan Ly's Direct Testimony Pages 11-12 (Average & Excess) Case U-21490;
Exhibit A-57 (SMG-6)	Detailed Analysis of FERC Account 378.

Q. Were these exhibits prepared by you or under your supervision?

A. Exhibits A-16 (SMG-1), Schedule F-1; A-16 (SMG-2), Schedule F-1.1, A-54 (SMG-3), A-55 (SMG-4), and A-57 (SMG-6) were all prepared by me or under my direction and supervision. Exhibit A-56 (SMG-5) was taken from the transcript in Consumers Energy's last gas rate case, Case No. U-21490.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. COST OF SERVICE OVERVIEW

II. TEST YEAR COST OF SERVICE - VERSION 1

III. TEST YEAR COST OF SERVICE – VERSION 2

IV. IMPACT OF UTILIZING THE A&E METHOD

V. DETAILED ANALYSIS OF FERC ACCOUNT 378

VI. PRODUCTS CREDIT ALLOCATION

I. COST OF SERVICE OVERVIEW

Q. What is COSS?

A. A COSS is a three-part analysis that quantifies the utility's cost to serve each rate class. It provides the utility and stakeholders with important information regarding each rate class's contribution to the total revenue requirement and the nature of those costs. Ultimately, the information provided by the COSS is used to guide rate design among other things. The fundamental guiding principle used to assign costs in the COSS is cost causation. In other words, the costs assigned to a customer or group of customers should reflect how those customers drive or influence the utility's costs.

Q. What are the three parts or steps involved in performing a COSS?

A. The first step is functionalization, followed by classification, and finally allocation. Cost functionalization involves the identification and separation of plant and expenses into specific categories based on the activity or "function" that each cost is incurred to provide or support. Consumers Energy's functional cost categories are Transmission, Distribution, and Storage. Cost classification, the second step, involves the categorization of functionalized costs into demand, customer, and energy components according to the primary cost drivers. The final step is cost allocation. Allocation assigns costs to each customer class using a variety of factors that correlate to the identified cost drivers. Common allocation factors include the number of customers, throughput or usage, and peak consumption among others. This process is relatively standard across the utility industry and supported by the National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual.

II. TEST YEAR COST OF SERVICE - VERSION 1

Q. Please describe Exhibit A-16 (SMG-1), Schedule F-1.

A. Exhibit A-16 (SMG-1), Schedule F-1, is a 16-page exhibit that summarizes the results of the Version 1 COSS. As explained earlier in my testimony, the Version 1 COSS employs the methodologies previously adopted by the Commission in Case No. U-20650 updated for the financial information and supporting data sponsored by other witnesses in this case. The Company also made routine updates for historical and test year data that are used to derive COSS cost detail and the various functional, classification, and allocation factors. Page 1 of the exhibit summarizes the results of the COSS; total Company gas information for the test year is found in column (d) while columns (e) through (l) breakout the cost to serve for each rate class. Total rate base by rate is shown on line 33 with the return on rate base shown on line 37. Adjusted net operating income is shown on line 32 and is calculated by subtracting test year total expenses from revenue, adjusting for Allowance for Funds Used During Construction. The associated income and revenue deficiencies are shown on lines 41 and 42 respectively and are supported by Company witness Heather L. Rayl. The proposed base rate design revenue target for each rate class, which is shown on line 46, is found by removing Cost of Goods Sold and miscellaneous revenue from the total cost of service. Page 2 provides a breakout of the proposed base rate design revenue target by rate class for each functional cost category (transmission, storage, and distribution). Exhibit A-16 (SMG-1), Schedule F-1, pages 3 through 10, provide detail on rate base, operating and maintenance ("O&M"), and revenue that supports the summary information presented on Exhibit A-16 (SMG-1), Schedule F-1, pages 1 and 2. Exhibit A-16 (SMG-1), Schedule F-1, pages 11 through 16, support the functionalization, classification, and allocation factors utilized in the COSS.

III. <u>TEST YEAR COST OF SERVICE – VERSION 2</u>

Q. Please describe Exhibit A-16 (SMG-2), Schedule F-1.1 and explain how it differs from the Version 1 COSS (Exhibit A-16 (SMG-1), Schedule F-1).

A. Exhibit A-16 (SMG-2), Schedule F-1.1 is a 16-page exhibit that starts with the Version 1 COSS (Exhibit A-16 (SMG-1), Schedule F-1) and incorporates the three Company proposals cited earlier in my testimony to: (1) remove asset retirement costs ("ARC") from the calculation of other distribution plant; (2) break out and allocate other distribution plant by FERC account; and (3) breakout and separately allocate CCC and BCC expenses. The page and line references in the Version 1 COSS also apply to Version 2. A summary of the results of the Version 2 COSS results and how it compares to Version 1 for each rate class is shown in Table 1.

Table 1: Summary of COSS Impact by Rate ($ in Millions)

Table 1: Summary of COSS Impacts by Rate ($ in Millions)

Description	Total	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
Present Revenue	$ 1,547	$ 1,111	$ 173	$ 132	$ 29	$ 35	$ 27	$ 30	$ 10
Version 1 Update	$ 248	$ 191	$ 14	$ 6	$ 3	$ 13	$ 9	$ 11	$ 2
Version 1 COSS	$ 1,795	$ 1,302	$ 187	$ 137	$ 32	$ 48	$ 36	$ 41	$ 12
	16.0%	17.2%	8.3%	4.5%	10.7%	36.7%	32.2%	34.8%	20.6%
+Remove ARC	$ -	$ 7.4	$ (0.4)	$ (1.7)	$ (0.5)	$ (0.9)	$ (1.0)	$ (2.0)	$ (0.8)
+Other Dist. FERC	$ -	$ 2.1	$ (0.0)	$ (0.3)	$ (0.1)	$ (0.2)	$ (0.3)	$ (0.8)	$ (0.3)
+BCC/CCC	$ -	$ 2.0	$ 0.7	$ (0.9)	$ (0.3)	$ (0.5)	$ (0.4)	$ (0.4)	$ (0.1)
Version 2 COSS	$ 1,795	$ 1,313	$ 187	$ 134	$ 31	$ 46	$ 34	$ 38	$ 11
	16.0%	18.2%	8.4%	2.2%	7.5%	32.0%	26.0%	24.3%	8.7%

A) <u>Asset Retirement Costs</u>

Q. Please explain why the Company is proposing to remove ARC from other distribution plant.

A. The Company is proposing to remove ARC from the COSS calculation of other distribution plant because these costs are not included in the distribution plant revenue requirement. The Company submitted this same proposal in Case Nos. U-21308 and U-21490 which was not contested by any party in that case and was adopted in the settlement COSS.

As shown in Table 2, removing ARC decreases the percentage of distribution plant categorized as "Distribution Plant – Other" from 8.61% to 5.81% and increases the share of plant in other categories.

Table 2: Comparison of Distribution Plant Major Categories

Distribution Plant Major Categories	Version 1	Version 2
Distribution Plant – Other	8.61%	5.81%
Mains – High Pressure Capable	4.17%	4.30%
Mains – Non-High Pressure Capable	27.36%	28.20%
Services & Meters	59.86%	61.69%

B) Breakout of Other Distribution Plant by FERC Account

Q. Please explain how the COSS has treated other distribution plant in the past.

A. Historically, the Company has allocated other distribution plant using Allocator 105. It includes volumes from customers attached to high-pressure mains and customers attached to non-high-pressure mains with an adjustment that removes volumes that bypass the high-pressure system. In Case Nos. U-21148 and U-21308, the Company proposed using Allocator 104 in place of Allocator 105 since Allocator 104 is based on total annual throughput and peak month throughput.

Q. Please explain why the Company is proposing to break out other distribution plant in this case.

A. In Case No. U-21308, ABATE witness Jonathon Ly argued it is not appropriate for other distribution plant be allocated in aggregate because the accounts included serve different functions. In rebuttal, the Company agreed to breakout other distribution plant costs on a more detailed FERC account basis in the next rate case which was formally reflected in the Case No. U-21308 settlement agreement. This same breakout was included in Case No. U-21490 and was formally reflected in the Case No. U-21490 settlement agreement.

Q. What FERC accounts are included in other distribution plant?

A. Other distribution plant includes costs in FERC Accounts 374, 375, 377, 378, and 382 where:

- **Account 374 Land & Land Rights** includes cost of land and land rights used in connection with distribution operations. The attainment of Land and Land Rights (Fee Land or Right of Way Easement) for roads or driveways, regulator stations, and tree rights is the foundation to lay down the Company's distribution system.

- **Account 375 Structures and Improvements** includes cost of structures and improvements used in connection with distribution operations. Structures and improvements to Gas Boiler Building, Gas Odorizing Station Building, Gas Regulator Building, etc. are critical to the safe and reliable operations of the Company's distribution system. They benefit all customers.

- **Account 377 Compressor station equipment** includes costs of installed compressor station equipment and associated appliances used in connection with distribution system operations. Air Compressors, Detectors, Sensors, Transformers, Transmitters, Valves, Uninterruptible Power Supplies, etc. are critical to the safe and reliable operations of the Company's distribution system. They benefit all customers.

- **Account 378 Measuring and regulating station equipment** generally includes costs of installed meters, gauges, and other equipment used in measuring and regulating gas in connection with distribution system operations other than the measurement of gas deliveries to customers. They are critical to the safe and reliable operations of the Company's distribution system. They benefit all customers.

- **Account 382 Meter installations** include cost of labor and materials used and expenses incurred in connection with the original installation of customer meters. Examples include installations of meters, rotary meters, meter regulator bypasses, Gas Sampler, etc.

Q. How is the Company proposing to allocate other distribution plant for FERC Accounts 374, 375, 377 and 378?

A. The Company proposes to allocate other distribution plant using Allocator 104 for FERC Account 374, 375, 377 and 378. Costs in these FERC accounts, as described above, are incurred to serve all customers. Since Allocator 104 is based on each rate class's respective forecasted total annual throughput and peak month throughput, the Company believes it is an improvement over Allocator 105 which excludes volumes that bypass the high-pressure system.

Q. How is the Company proposing to allocate other distribution plant for FERC Account 382?

A. The Company proposes to allocate other distribution plant using Allocator 108 for FERC Account 382. Costs in this FERC account, as described above, are incurred in connection with the original installation of customer meters. Since Allocator 108 is weighted by the average residential customer hook up cost and is based on each rate class's respective forecasted average number of customers, the Company believes it is an improvement over Allocator 104 which is based on each rate class's respective forecasted total annual throughput and forecasted peak month throughput.

C) Customer Care Center and Business Customer Care Expense

Q. How have CCC and BCC costs been allocated to customers in the past?

A. Historically, CCC and BCC costs were included in the COSS line item "O&M Excluding A&G" which gets divided among several sub-categories using historic ratios and assigned a variety of allocators.

Q. How is the Company proposing to allocate CCC and BCC costs in Version 2 of the COSS?

A. The Company has broken out CCC and BCC costs as separate line items in the COSS and developed two new allocators: Allocator 114 which calculates the share of customers (by rate class) using the BCC, and Allocator 115 which calculates the share of customers (by rate class) using the CCC. The CCC serves residential and small business customers while the BCC serves commercial and industrial customers. Because business customers may utilize the CCC or BCC, the Company obtained data on the number of customers by rate class served by the BCC as a reasonable measure of resource utilization and cost causation. This data was then used to calculate both Allocators 114 and 115. Support for these calculations can be found in WP-SMG-25.

IV. IMPACT OF UTILIZING THE A&E METHOD

Q. Please explain why the Company is presenting the A&E method in this case.

A. In the Case No. U-21490 settlement agreement the Company agreed to provide a COSS that calculated the impact of utilizing the A&E method. The COSS results using the A&E method can be found in Exhibit A-54 (SMG-3).

Q. Please explain how the A&E method is calculated.

A. The A&E method is comprised of two components. The first component is based on average annual throughput weighted by a utility's system load factor. The second component considers the non-coincident peak ("NCP") which is derived using each class's maximum monthly throughput. To calculate the NCP method in this case, the Company relied on the A&E method developed in ABATE witness Ly's Direct Testimony and Workpapers in Case No. U-21490. Support for each class's NCP calculation can be found in WP-SMG-26. Mr. Ly's Direct Testimony from Case No. U-21490 (pages 11-12) can be found in Exhibit A-56 (SMG-5).

Q. What is the impact of utilizing the A&E method on the COSS results?

A. Table 3 shows how the results of the A&E COSS compared to the results of the Version 2 COSS:

Table 3: A&E COSS Impacts by Rate Class ($ in Millions)

Table 3: Summary of A&E Method ($ in Millions)

Description	Total	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
Version 2 COSS	$ 1,795	$ 1,313	$ 187	$ 134	$ 31	$ 46	$ 34	$ 38	$ 11
A&E COSS	$ 1,795	$ 1,310	$ 188	$ 132	$ 33	$ 49	$ 33	$ 35	$ 13
Difference	$ -	$ (3)	$ 1	$ (2)	$ 2	$ 3	$ (1)	$ (2)	$ 2
	0.0%	-0.2%	0.4%	-1.5%	6.5%	5.8%	-2.5%	-5.9%	21.6%

Q. Is the Company proposing to adopt the A&E method?

A. No. While the Company believes the A&E method is reasonable and makes some improvements to the A&P method, the Commission has consistently ruled in favor of using the A&P method to allocate distribution mains costs, such as in Case No. U-10150, Case No. U-18124, and Case No. U-20322, to name a few.

V. <u>DETAILED ANALYSIS OF FERC ACCOUNT 378</u>

Q. Please explain why the Company is presenting a detailed analysis of FERC Account 378.

A. In the Case No. U-21490 settlement agreement, the Company agreed to provide a study with a more detailed analysis of FERC Account 378. Specifically, the Company agreed to:

(1) Identify the costs in FERC Account 378 associated directly with measuring and regulator stations;

(2) Identify, with as much granularity as available, all other costs contained in FERC Account 378;

(3) Identify the total number of measuring and regulator stations in FERC Account 378 that regulate pressure from (a) high-pressure mains to high- pressure mains, (b) high-pressure mains to non-high-pressure mains, and (c) non-high-pressure mains to non-high-pressure mains; and

(4) Provide an analysis, either based on existing costs or an estimate of building new assets, that would allow for the allocation of measuring and regulator station costs between high pressure and non-high pressure.

Q. Please explain how Exhibit A-57 (SMG-6) addresses the settlement agreement language from parts 1 through 3 from the settlement agreement in Case No. U-21490.

A. Exhibit A-57 (SMG-6) contains the costs in FERC Account 378 associated directly with measuring and regulator stations on line 1, column e. The remaining costs contained in FERC Account 378 include the Huron Compressor station costs, the total of which are show in Exhibit A-57 (SMG-6) line 2, column e, and gas Odorization costs on line 3, column e. The Huron Compressor station serves to increase the pressure of the Company's high-pressure distribution system in Huron County to meet the demands of all customers during the highest demand days. Odorization serves as a safety measure for all customers and as such should be allocated to all customers.

The total number of measuring and regulator stations in FERC Account 378 that regulate pressure from high-pressure mains to high-pressure mains are shown on line 5, column c. The total number of measuring and regulator stations in FERC Account 378 that regulate pressure from high-pressure mains to non-high-pressure mains are shown on line 6, column c. The total number of measuring and regulator stations in FERC Account 378 that regulate pressure from non-high-pressure mains to non-high-pressure mains are shown on line 7, column c.

Q. Please explain how Exhibit A-57 (SMG-6) addresses the settlement agreement language from part 4 from the settlement in Case No. U-21490.

A. The data contained in Exhibit A-57 (SMG-6), lines 5 through 7 provides the necessary information to separate and functionalize the costs in FERC Account 378 that service high-pressure mains and those that serve non-high-pressure mains. This detail can be used to determine an allocator to distribute the share of costs for high pressure and non-high pressure.

Q. Why do the total book values in line 1, column e not match to the total book value in line 7 column e?

A. The values in line 1, column e, reflect the Company's property accounting records for FERC Account 378 based on a typical life cycle of the measuring and regulator station assets. The values in line 8, column e, reflect the total book value of active measuring and regulator station assets recorded in the Company's GIS database. There is typically a delay between when an asset is modified and when the asset's book value is formally adjusted in the Company's property accounting records. The Company is continually reviewing its internal data to reconcile the values in lines 1 and 8. For these reasons, the data from lines 5 through 8 in Exhibit A-57 (SMG-6) provides the most representative data to develop an allocation of measuring and regulator station costs between high pressure and non-high pressure.

VI. PRODUCT CREDIT ALLOCATION

Q. How does the Company propose allocating the projected revenue generated by the Home Products Credit?

A. The Company proposes using Allocator 209 (Total O&M excluding Admin & General) as demonstrated in Exhibit A-55 (SMG-4). The Company invests O&M into the Home Products program and Allocator 209 is the total O&M allocator that includes working capital and excludes Admin & General. The Company believes it is reasonable to credit, proportionally, those who have paid for the program in the allocation of the Home Products Credit.

Q. Does this complete your direct testimony?

A. Yes.

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 for other relief.	)))))	Case No. U-21806

DIRECT TESTIMONY

OF

MICHAEL P. GRIFFIN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Michael P. Griffin, and my business address is 4600 Coolidge Highway, Royal Oak, MI 48073.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I presently hold the position of Senior Strategy Manager in the Gas Strategy Department, a position I have held since July 2021.

Q. What are your responsibilities as Senior Strategy Manager?

A. I am responsible for the cross-functional research, analysis, and oversight of natural gas transmission and certain distribution assets and transmission portfolio management strategy. This includes the development, recommendation, and administration of the Natural Gas Delivery Plan ("NGDP").

Q. Please describe your educational background?

A. I earned a Bachelor of Arts in Marketing from Michigan State University in 1985, and earned a Master of Business Administration from Wayne State University in 1998.

Q. Please describe your work experience?

A. I began working for the Company in 1987. Since that time, I have held positions of increasing responsibility including Marketing Consultant, Customer Energy Specialist, Senior Business Support Consultant in the financial area, Gas Budgeting Director, and Director of Rate Cases and Controls, a position I held beginning in 2008. As Director of Rate Cases and Controls, I was instrumental in the development of testimony and exhibits, and in supporting various witnesses in multiple gas and electric rate cases for the Gas and

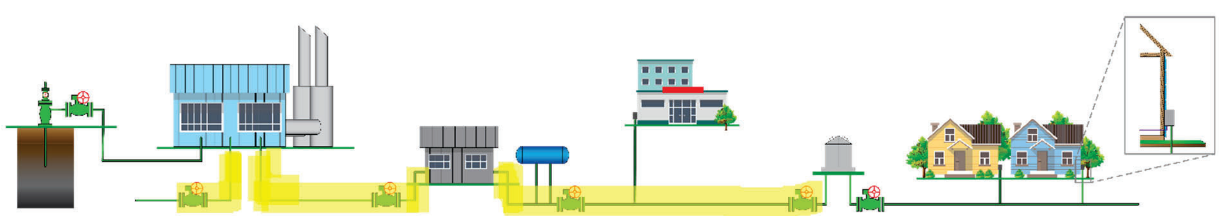
Electric Engineering, Operations, and Customer Operations departments. Since July 2021, I have held the role of Senior Strategy Manager for the Company's transmission assets.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have recently provided testimony in MPSC Case No. U-21148, MPSC Case No. U21308 and MPSC Case No. U-21490.

Q. What is the purpose of your direct testimony?

A. My direct testimony explains the Company's request for rate relief as it relates to its Gas Transmission and certain Distribution capital expenditures and Operating and Maintenance ("O&M") expenses for the programs identified below. These expenditures are primarily related to operations of the Company's high-pressure distribution and transmission systems. Specifically, these investments relate to the portion of the Company system that receives the high-pressure gas at the outlet of the Compressor Stations, and delivers the gas to the city gates, and from the city gates to the regulator stations. In the diagram below, these investments are inside the yellow highlighted section. These investments will help the Company meet its objectives of supplying safe, reliable, affordable, and clean energy to customers as described in the NGDP, Exhibit A-42 (NPD-1), sponsored by Company witness Neal P. Dreisig.



My direct testimony is divided into three sections: (i) Asset Relocation Transmission capital expenditures; (ii) Regulatory Compliance O&M and capital costs; and (iii) Capacity/Deliverability capital expenditures.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-58 (MPG -1)		Summary of Actual & Projected Regulatory Compliance O&M Expenses;
Exhibit A-12 (MPG-2)	Schedule B-5.5	Summary of Actual and Projected Capital Expenditures Transmission & Distribution Plant - Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-59 (MPG-3)		Actual & Projected Gas Transmission Capital Expenditures - Asset Relocation Transmission Program;
Exhibit A-60 (MPG-4)		Actual & Projected Gas Transmission Capital Expenditures – Regulatory Compliance Program;
Exhibit A-61 (MPG-5)		Actual & Projected Gas Transmission and Distribution Capital Expenditures - Capacity/Deliverability Program;
Exhibit A-62 (MPG-6)		Actual & Projected Gas Capital Expenditures - Transmission & Distribution Plant - TED-I Program Detail; and
Exhibit A-63 (MPG-7)		Projected Capital Expenditures - Transmission & Distribution Plant, Summary of Actual & Projected Gas Capital Expenditures.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. Please describe Exhibit A-58 (MPG-1).

A. Exhibit A-58 (MPG-1) shows the total O&M expenses for the Regulatory Compliance Program that I am sponsoring. In my testimony, I will describe the program expenses and projects contained within this program. As shown on line 5 of Exhibit A-58 (MPG-1), the total O&M expenses I am sponsoring were $20,034,000 in 2023 and are projected to be $26,737,000 in 2024, $28,512,000 in 2025, and $23,129,000 for the 12 months ending October 31, 2026.

Q. Please describe Exhibit A-12 (MPG-2), Schedule B-5.5.

A. Exhibit A-12 (MPG-2), Schedule B-5.5, shows the total capital expenditures I am sponsoring. In my testimony I will describe each of the programs, any sub-programs, and corresponding expenditures for these items. As shown on line 4 of Exhibit A-12 (MPG-2), Schedule B-5.5, the capital expenditures for the programs I am sponsoring were $350,582,000 in 2023, and are projected to be $313,829,000 in 2024, $176,781,000 for the 10 months ending October 31, 2025, and $219,855,000 for the 12 months ending October 31, 2026.

Q. Does the NGDP discuss the Company's gas transmission assets?

A. Yes, it does.

Q. Please describe the Company's 10-year investment plan for its gas transmission and distribution assets that you are sponsoring.

A. Over the next 10 years, the Company will focus its transmission efforts to continue improving on inspections, reducing risk, and increasing its remediation pace for critical assets. To reach these objectives, the Company has completed the planned Transmission Enhancements for Deliverability & Integrity ("TED-I") pipeline projects and will be moving forward with smaller-scale infrastructure projects like valve replacements and upgrades, along with line lowerings and the re-build schedule for city gate facilities. This information can be found in Exhibit A-42 (NPD-1), Section IV.C Transmission Asset Plan of the NGDP. The Company is also rebuilding distribution regulator station facilities. This information can be found in Exhibit A-42 (NPD-1), Section IV.D of the NGDP.

I. ASSET RELOCATION TRANSMISSION PROGRAM

Q. Please describe the capital expenditures related to the Asset Relocation Transmission Program as shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 1.

A. The Asset Relocation Transmission Program includes gas transmission infrastructure replacement projects that are required due to civic improvement activities, initiated by federal, state, or local governmental units. This program also includes projects where transmission pipeline location or depth of cover requires relocation of an existing pipeline to prevent third-party damage, eliminate physical conflicts with other utilities, and ensure continued safe operation. Civic improvement projects replace or improve aging public infrastructure such as roadways, bridges, sewer lines, water lines, and drainage ditches. The Transmission Pipeline Engineering Department reviews all civic improvement projects to determine if conflicts require pipeline relocation. The Asset Relocation Transmission Program also includes relocation and lowering of natural gas transmission infrastructure to remediate reduction in cover due to grading and/or erosion.

For actual and potential asset relocation projects reviewed as a result of civic improvement projects, to minimize scope and expense, the Company works with the governmental units involved to coordinate work and to negotiate design criteria wherever possible. For instance, the Company reviews municipal project plans and tries to negotiate design changes to eliminate potential direct conflicts with Company facilities, such as gas transmission lines, valve sites, or city gate stations. These negotiations reduce overall project scope and thus reduce the costs to both the taxpayer and the customer.

In addition, to further reduce costs, the Company coordinates project timelines with municipalities to align construction and restoration schedules. An example of the Company's ongoing coordination with municipalities in which civic improvement projects required pipeline relocation was in Oakland County when lowering segments of Line 1600 along Taft Road ahead of scheduled municipal road improvements planned by the City of Novi. This effort was undertaken to minimize disturbance and impact to the community. Furthermore, additional coordination in Saginaw County allowed the Company to lower a segment of Line 300 within the Parker Swamp Drain to safely facilitate scheduled drain maintenance activities.

Projects are also scoped as a result of instances where location or lack of depth of cover requires the relocation of an existing transmission pipeline to ensure continued safe operation and for damage prevention purposes. Projects are evaluated to determine if the reestablishment of cover can be a long-term, viable remediation option. Most projects are not selected for this type of remediation method given the likelihood of continued cover degradation over a period of time. The Asset Relocation Transmission Program projects are designed and constructed to comply with minimum soil cover requirements specified by State and Federal regulations, see, e.g., 49 CFR 192.317, 49 CFR 192.327(a), Michigan Gas Safety Standards, and Company requirements. These project types are described in more detail later in my direct testimony.

As shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 1, the capital expenditures for this program were $6,168,000 in 2023, and are projected to be

$17,389,000 in 2024, $19,138,000 for the 10 months ending October 31, 2025, and $24,726,000 for the 12 months ending October 31, 2026.

Q. Please describe the development of the Company's Asset Relocation Transmission Program capital expenditure projections.

A. These projections are based upon knowledge of specific projects planned for the next several years and prioritized accordingly by established risk and/or external third-party/civic schedule commitments. Examples of asset relocation projects included in these projected expenditures include:

- Line 300 Parker Swamp Drain Lowering civic improvement in Saginaw County;
- Line 1300 114th Ave line lowering in Allegan County;
- Line 100B Sleepy Hollow State Park ("SHSP") re-route in Clinton County;
- Lines 100A/B/C Chippewa River line lowerings in Isabella County;
- Line 1100 Rabbit River line lowering in Allegan County;
- Line 1200A line lowerings at Wetlands BR014 and BR017 in Branch County;
- Line 1200A Townline Road line lowering in Branch County; and
- Line 1200A Needham Road line lowering in Branch County.

The Company's projected expenditures are required to complete the level of asset relocations for known transmission line lowerings and civic improvement projects. Exhibit A-59 (MPG-3) provides further details on the expenditures included in this program.

Q. Please describe the Line 100B SHSP re-route project.

A. The Company filed for a certificate of public convenience and necessity pursuant to 1929 Public Act 9 ("Act 9") in MPSC Case No. U-21179 on December 15, 2021, for this project. The Act 9 was approved on March 3, 2022. The project was completed in 2024. As described in the Company's Application, page 2, in that case:

> In Case No. U-20618, Consumers Energy received Commission approval pursuant to Act 9 to construct and operate the Mid-Michigan Pipeline to replace the existing Line 100A pipeline between Chelsea and Ovid, Michigan… The Mid-Michigan Pipeline includes a reroute of Line 100A in SHSP away from the campground and beach area to allow for construction during the busy use of the park and removal of the pipeline from heavily used areas… Line 100B is a 26-inch natural gas pipeline that runs parallel to Line 100A through SHSP. Consumers Energy proposes to reroute Line 100B at the same time, and along the same route, as Line 100A. Just as with Line 100A, rerouting Line 100B will remove the pipeline from the heavily used beach and campground areas, and as a result will remove the addition of a valve site due to the reroute being located in a Class 2 area. Removal of the valve site will save approximately $1 million. The reroute away from the beach and campground areas will also result in less impact to park users in the event of future pipeline maintenance or remediation. The reroute of Line 100B will allow Line 100B to continue to parallel Line 100A, which will provide for more efficient and cost-effective maintenance of the pipelines in a single pipeline corridor. Line 100B is currently buried deeper than normal in the park, and rerouting Line 100B will allow the pipeline to be brought to normal depth allowing for improved operations and maintenance.

Q. Please explain the methodology for selecting the Company-initiated projects in the Asset Relocation Transmission Program.

A. Company-initiated projects executed under the Asset Relocation Transmission Program are selected based on a variety of considerations, including physical depth of cover, customer notifications, and Consumers Energy transmission pipeline risk model results, as determined by the Gas Asset Management System Integrity group. Risk modeling for the Asset Relocation Transmission Program involves determining the anticipated overall risk reduction that would result from reducing the relative risk score for third-party damage (by a percentage commensurate with increased depth of cover) and holding all other individual threat risk scores constant. Segments showing a higher overall risk reduction as a result of increased depth of cover are graded as higher priority within the Asset Relocation Program. Prioritization may also be adjusted based on availability of transmission pipeline outages, continued coordination with local municipalities or governing authorities for civic-related work, and anticipated future replacement under another program (such as TED-I).

Q. Please describe the customer benefits attained from the projects in this program.

A. For Company-initiated Asset Relocation Transmission Projects, replacing and lowering pipeline segments in locations where grading or erosion has reduced cover to less than the depths specified by 49 CFR 192.327(a) and Company standard requirements provides benefits to customers by reducing the potential for third-party damage from activities such as plowing and drain maintenance. For example, industry data for risk management indicates that increasing the depth of cover from 3.0 feet to 4.5 feet reduces the threat of third-party damage occurrence by up to 56% (Muhlbauer, Pipeline Risk Management Manual). These projects also mitigate the risks of additional reduction in cover and future exposure of pipelines, which may in turn result in increased risk of vehicle damage, external loading, coating damage, pipe scouring, washouts, sinking, and corrosion at the soil-to-air interface. For Asset Relocation Transmission Projects initiated by civic improvement projects, customer benefits include reduced risk of third-party damage, maintenance of underground clearances specified by 49 CFR 192.325, and facilitation of the civic improvement projects. Customers also benefit when the Company coordinates with civic improvement projects as street and road disruptions are minimized.

II. REGULATORY COMPLIANCE PROGRAM

Q. Please describe the capital expenditures related to the Regulatory Compliance Program as shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 2.

A. As shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 2, the capital expenditures for this program were $36,139,000 in 2023, and are projected to be $26,078,000 in 2024, $24,285,000 for the 10 months ending October 31, 2025, and $24,807,000 for the 12 months ending October 31, 2026.

I am sponsoring the following four programs in the Regulatory Compliance capital program:

- Pipeline Integrity Transmission Program;
- Pipeline Integrity Transmission Operated by Distribution ("TOD") Program;
- Cathodic Compression, Storage and Pipeline Program; and
- Maximum Allowable Operating Pressure ("MAOP") Compliance Pipeline Program.

Q. Please describe the O&M expenses related to the Regulatory Compliance Program as shown on Exhibit A-58 (MPG-1).

A. As shown on line 5 of Exhibit A-58 (MPG-1), the O&M expenses for this program were $20,034,000 in 2023 and are projected to be $26,737,000 in 2024, $28,512,000 in 2025, and $23,129,000 for the 12 months ending October 31, 2026.

I am sponsoring the following four programs in the Regulatory Compliance O&M program:

- Pipeline Integrity Transmission O&M Program;
- Pipeline Integrity TOD O&M Program;
- Corrosion Control Transmission O&M Program; and

- MAOP Transmission O&M Program.

As these O&M expenses are primarily tied to the capital expenditures in the capital programs described above, they will be consolidated below to describe the overall program spending.

A. PIPELINE INTEGRITY TRANSMISSION PROGRAM AND PIPELINE INTEGRITY – TOD PROGRAM

Q. Please describe the Pipeline Integrity Program.

A. The Pipeline Integrity Program represents the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration ("PHMSA") and the Commission. The program costs are a function of the overall number of assessments, inspection tool types, baseline assessments, or reassessments to be completed in accordance with the Company's Pipeline Integrity Program.

Q. Please describe PHMSA's requirements for a Pipeline Integrity Program.

A. Federal Regulation, 49 CFR Part 192, Subpart O, specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of natural gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas ("HCA"). These are areas where pipeline releases could have greater consequences to health, safety, or the environment. As a transmission pipeline operator, Consumers Energy must comply with these minimum federal safety standards. Under 49 CFR 192.907, by December 17, 2004, all pipeline operators, including Consumers Energy, were required to develop and follow a written Transmission Integrity Management Program ("TIMP") that addresses the risks on each covered transmission pipeline segment. In addition, Consumers Energy has updated its standards, procedures, and processes to adhere to the additional requirements in Safety of Gas Transmission Pipelines, including Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments ("RIN2") by May 24, 2023, and other dates as outlined in the final rule.

Q. Please describe the MPSC's requirements for a Pipeline Integrity Program.

A. The MPSC has adopted and is the enforcement agency for the federal regulations. Additionally, the MPSC has published the Michigan Gas Safety Standards. These standards are additional rules the Company is required to follow.

Q. What is the importance of a Pipeline Integrity Program?

A. As stated above, a Pipeline Integrity Program is in place to validate and ensure the integrity of pipelines in HCA and outside of HCA, including inline inspectable Moderate Consequence Areas ("MCA") and segments within a Class III or Class IV location operating above 30% specified minimum yield strength ("SMYS"). This program provides a critical avenue that increases public safety through the identification and remediation of potentially hazardous conditions on the pipelines. Additionally, the program is important to ensure the reliability of the Company's transmission system remains intact by taking measures to prevent an unexpected failure on the system.

Q. How was the Company's Pipeline Integrity Program developed?

A. Consumers Energy's TIMP contains information related to how the Company identifies, prioritizes, assesses, evaluates, repairs, and validates the integrity of its gas transmission pipelines that could, in the event of a leak or failure, affect HCA. The TIMP is updated based upon regulations that have become effective since the inceptions of the program. To minimize environmental and safety risks, Consumers Energy's TIMP delivers the following:

- Identifies HCA, required assessments Outside of HCA, and threats to covered pipeline segments:
    - Assessments Outside of HCA
        - Inline Inspectable MCA; and
        - Segments located within a Class III or IV location operating above 30% SMYS;
- Establishes a baseline assessment plan, including criteria for establishing reassessment intervals, a direct assessment plan, and a communication plan;
- Remediates conditions found during assessments;
- Specifies continual evaluation and assessment of the overall TIMP;
- Establishes a plan for confirmatory direct assessment;
- Requires additional preventative and mitigative measures, recordkeeping, and management of change; and
- Establishes a Quality Assurance process.

Pursuant to the federal regulations, this written document has been modified over the years for various reasons. Some of the reasons for modification include changes in inspection technology, changes or clarifications received from PHMSA, feedback from the MPSC Staff ("Staff"), and Company-driven changes.

Q. Is the TIMP Manual provided to Staff?

A. Yes. Staff has access to the Company's TIMP Manual, and when revisions to the TIMP Manual are made, a copy is sent to Staff.

Q. As part of Transmission Integrity Management, do companies need to continuously improve their program?

A. Yes, 49 CFR 192.907 and 49 CFR 192.911 require that an operator must make continual improvements to the program.

Q. Does the Company's NGDP, Exhibit A-42 (NPD-1), discuss Consumers Energy's 10-year plan related to the Pipeline Integrity Program?

A. Yes. Over the 10-year period of the NGDP, the Company is focusing on improving inspections, de-risking, and increasing its remediation pace for critical assets. The Company is continuing its current practice of striving toward six-year inspection and remediation cycles. The Company is updating its risk ranking methodology and transitioning its current relative risk model into a probabilistic risk model to ensure investments are concentrated on the right assets. As discussed in the NGDP, the Company will undertake the following:

- Complete baseline inspections for approximately 25 miles of the Company's mainline transmission system pipeline by year-end 2025 and maintain that plan based on a reassessment plan;
- Assess and develop a plan to proactively remediate high-risk pipe segments that are prone to higher risk threats like Stress Corrosion Cracking ("SCC") and corrosion; and
- Evaluate transmission-classified segments embedded in the distribution system—referred to as TOD—to determine if a baseline assessment or replacement is needed on a prioritized basis.

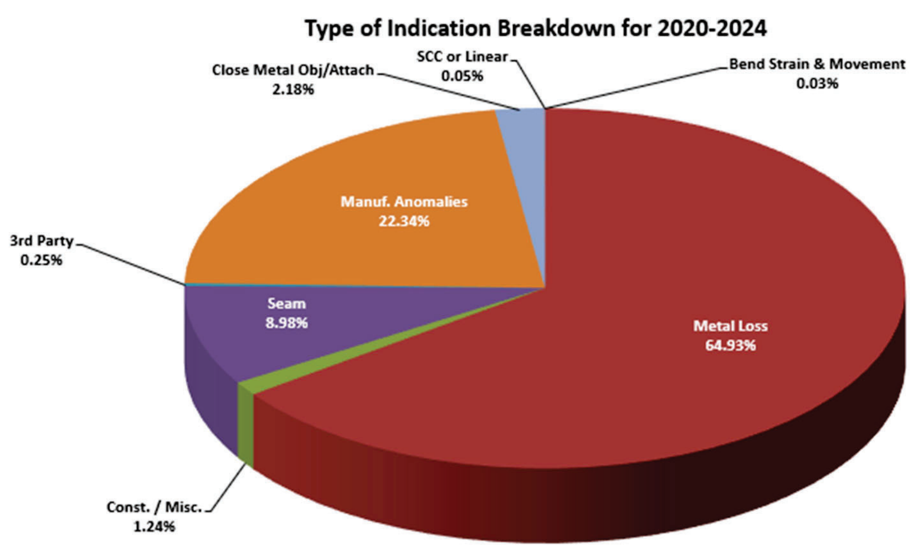
Exhibit A-42 (NPD-1), Section IV.C.2, provides additional information on these objectives.

Q. What types of anomalies and threats has the Company experienced on its gas transmission system?

A. Consumers Energy's TIMP has proven to find anomalies the Company is able to remediate, providing safe and reliable operations for customers. The Company has experienced several different types of anomalies on its gas transmission system, and continues to find new pipeline safety threats that require mitigation, as detailed later in my direct testimony. A breakdown of the type of anomalies found through traditional in-line inspection ("ILI") tool runs from 1999 to 2024 is shown in the Figure 1 below:

Figure 1

Type of Anomalies Found Through ILI Tool Runs 2020 through 2024



The anomaly indications are as follows:

1. Metal Loss encompasses all external and internal corrosion in the body of the pipe that has been predicted by the ILI tools;
2. Manufacturing anomalies include metal loss due to the manufacturing of the pipe and other manufacturing anomalies predicted in the body of the pipe;

3. Seam anomalies covers all external and internal corrosion in the seam weld, crack indications in the seam, and metal loss in the seam weld due to manufacturing processes;

4. Construction and Miscellaneous category include reinforced girth welds, sleeves, and other items that appear on or near the pipeline;

5. Metal Object and Attachment category includes extra metal and close metal objects to the pipelines;

6. Third-Party Damage includes any dents, deformations, and gouges on the pipelines;

7. SCC or Linear includes crack indications found in the body of the pipe and not on a seam; and

8. Locations on the system that have indication of Bend Strain or pipeline movement due to geohazards or construction activities.

As illustrated in the chart, the largest percentages of anomalies are metal loss or corrosion. From an industry perspective, corrosion is the number one threat to a transmission pipeline system. In keeping with regulatory and industry requirements, the Company promptly addresses this threat through a strong TIMP, and a robust corrosion control process that reduces the corrosion rate on pipelines.

The Company's TIMP program also addresses the threat of SCC. Many factors can affect the initiation and propagation of SCC, but a primary barrier to SCC is a pipeline's coating system. A secondary barrier is a cathodic protection system. When the coating on a pipe is compromised, the environmental factors that support SCC can develop under the right conditions. Since 2015, the Company has been assessing its pipelines that have the highest potential for SCC to occur, and there have been instances where SCC was found and remediated.

The Company also continues to conduct bending strain analyses and pipe movement studies on sections of its natural gas transmission system to identify potential areas of high strain on its transmission pipelines. Since 2017, the Company has performed 62 bending strain analyses and performed remediation based on those results to improve the safety and reliability of the system.

Q. Is a probabilistic risk model recommended by federal or state regulators?

A. Yes, both. PHMSA has identified the probabilistic risk model as a potential best practice for pipeline operators over other risk models, as discussed in the technical information document, Pipeline Risk Modeling: Overview of Methods and Tools for Improved Implementation, published February 1, 2020, by PHMSA. Additionally, the MPSC recommended the transition in its September 11, 2019 Michigan Statewide Energy Assessment Final Report ("SEA").

Q. What are the additional benefits of a probabilistic risk model for the safety and reliability to customers?

A. When transmission risk modeling was first required by PHMSA, the industry explored the best options available to comply with regulations. The best option available at that time was a relative risk model, which uses a scoring system to weight the different threats to the pipeline to rank the pipelines within a transmission system relative to each other. The scoring system used values based upon subject matter expert opinion and experience, and therefore, the model was not a true statistical model. A true statistical model, or probabilistic model, had not yet been developed for the industry due to its complexity. Therefore, the relative model provided the best method to assess risk and is what the Company has been using.

In the last several years probabilistic models have been developed, and show great promise as a tool in more accurately assessing pipeline risk. The use of a model that is entirely data driven provides a more accurate representation of the risks associated with pipelines. This in turn will allow the Company to more precisely mitigate risks associated with its transmission system to improve customer safety and reliability. While the inputs of the model are data driven, the model results will still require subject matter expert interpretation, verification, and understanding of those results. The Company has completed extracting, transforming, and loading of the data in addition to the asset configuration, training, and testing of the probabilistic risk model. The first run of the model was completed in 2023, The probabilistic risk model is utilized to prioritize work, to ensure the urgency of action taken is appropriate to mitigate the threats on that segment, and to ensure the correct mitigative actions are taken to ensure safe operation of the asset. This is a fully quantitative approach to risk modeling allowing an objective view of the risk, threats, and impacts related to the gas assets. The Company intends to implement probabilistic risk models in the future for other asset classes so that risk and risk reduction measures can be prioritized across the entire system using a more common scale, beginning with Storage assets with the probabilistic risk model implementation complete by year end 2024.

Q. Please explain the development of the Pipeline Integrity Transmission O&M expenses.

A. As shown on Exhibit A-58 (MPG-1), line 4, the Company's Pipeline Integrity - Transmission O&M expense was $17,089,000 in 2023, and is projected to be $22,275,000 in 2024, $23,110,000 in 2025, and $17,128,000 for the test year ending October 31, 2026. The mileage the Company intends to inspect in 2023 through 2026 is shown in Table 1 below. The O&M cost projections for remediation digs are based upon recent inline inspection results. The O&M includes costs for inspections, remediation, and where applicable material verification and MAOP reconfirmation.

Table 1

Inspection Mileage			
2023	2024	2025	2026
266.5	374.6	320.7	206.4

Additionally, there are certain baseline assessments on longer pipeline segments that will lead to additional digs. These expenses were not projected utilizing inflation factors.

Consumers Energy recognizes there is risk related to public safety and employee safety on pipelines outside of HCA, and is inspecting and remediating those segments, which are also included in the expenses in this program. Through previous inspections performed on non-HCA segments of pipeline, the Company has been able to gather additional data regarding the integrity of its overall transmission system. Similar anomalies are found in both non-HCA and HCA because the pipeline characteristics are the same. The data shows that most of the anomalies found and remediated on Consumers Energy's transmission system are in non-HCA.

Q. Are there additional activities included in the Company's Pipeline Integrity Transmission O&M expenses?

A. Yes. The Company's projection also includes the performance of geohazard assessments of the Company's transmission pipeline systems. These geohazard assessments will provide additional information on potential geohazard outside force threats to the Company's transmission pipelines. This additional information will inform the Company's risk/threat assessments and potential mitigative measures the Company can take to minimize those threats on the transmission system. Included in the projection is additional material testing on remediation digs where the Company does not have all necessary material properties as required by the Material Verification section of the Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments rule.

The Company's projection also includes the performance of bending strain analyses and pipe movement studies. Additionally, running Electro Magnetic Acoustic Transducer ("EMAT") tools on pipelines that are susceptible to SCC is part of this projection. Through the use of EMAT tools, the Company has detected and remediated different anomalies than what has previously been found using more traditional ILI tools.

Q. Please describe the Pipeline Integrity – TOD Program.

A. In addition to ILIs and remediation on the transmission system, the Company performs assessments of TOD pipe. These pipeline segments are operated on the distribution system above 20% Specified Minimum Yield Strength and thus are covered under the Transmission regulations. As shown on Exhibit A-58 (MPG-1), line 3, the Company's Pipeline Integrity – TOD Program O&M expenses were $812,000 in 2023, and is projected to be $1,059,000 in 2024, $1,085,000 in 2025, and $1,420,000 for the test year ending October 31, 2026. For pipe within HCA, the Company assessed 14.8 miles in 2023 and will assess 15.6 miles in 2024, 23.1 miles in 2025, and 11.8 miles in 2026. Assessments include inspection digs for External Corrosion Direct Assessment ("ECDA"), inspection digs for Internal Corrosion Threat Evaluation, or Internal Corrosion Direct Assessment ("ICDA"). Dig locations are determined from analysis of survey and historical corrosion issues. In addition, starting in 2023, the Company began performing ECDA assessments on non-HCA segments to reduce overall risk on TOD assets. The additional survey and assessment digs are why there is an increase in O&M expense between 2023 and 2026. The indirect surveys needed to perform the direct assessments are included in the O&M expense. Also, ECDA digs that result in coating repairs only, verification digs, and additional assessments on non-HCA pipelines are included in the projection.

Q. Please explain the development of the Pipeline Integrity - Transmission capital expenditures.

A. As shown on Exhibit A-60 (MPG-4), line 1, the capital expenditures for this program were $16,148,000 in 2023, and are projected to be $13,381,000 in 2024, $10,504,000 for the 10 months ending October 31, 2025, and $5,144,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 1, column (b); line 1, column (c); line 1, column (d); and line 1, column (f), respectively.

Pipeline Integrity - Transmission expenditures include remediation of pipeline anomalies where 50 feet or more of pipe is replaced, the installation of Ultrasonic Thickness ("UT") sensors, corrosion coupons, and robotic ILIs. Both UT sensors and corrosion coupons allow the Company to measure and determine the corrosion rate to determine current condition and potential replacement. Internal UT sensors physically measure the pipe wall and allow the Company to obtain this information without physically digging up the location. This reduces the need to re-excavate the same locations every seven years to evaluate the condition of the pipe as would be required if the sensor was not installed, thus reducing costs to determine the integrity of the pipe at that location. Corrosion coupons (external corrosion) tell the Company the corrosivity of the soil and the adequacy of the cathodic protection to help ensure system integrity. The Company anticipates 15% of the remediation digs will be capital.

Q. Please explain the development of the Pipeline Integrity – TOD Program capital expenditures.

A. As shown on Exhibit A-60 (MPG-4), line 2, the capital expenditures for this program were $9,274,000 in 2023, and are projected to be $6,119,000 in 2024, $5,593,000 for the 10 months ending October 31, 2025, and $9,998,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 2, column (b); line 2, column (c); line 2, column (d); and line 2, column (f), respectively.

As part of the direct assessments performed, UT sensors (for internal corrosion) and UT coupons (for external corrosion) are frequently installed to monitor corrosion rates. The corrosion rate information is then reviewed and evaluated to determine the effectiveness of corrosion control measures. To date, approximately 1,457 UT sensors and 916 UT coupons have been installed. Typical remediation of pipe found during the inspections involves pipe replacements.

Q. Are there any additional details you would like to provide regarding significant projects included in the Pipeline Integrity – TOD Program?

A. Yes. In 2023, new requirements were implemented that increased requirements for ICDA assessments. These changes increased the number of excavations required to complete an ICDA assessment. While there was an increase in dig requirements, installation of UT sensors during prior assessment digs reduce the total number of excavations being perform since many of the required locations were already being monitored.

B. CORROSION CONTROL – TRANSMISSION PROGRAM AND CATHODIC COMPRESSION, STORAGE, AND PIPELINE PROGRAM

Q. Please describe the Corrosion Control – Transmission O&M Program.

A. The O&M expense for the Corrosion Control – Transmission Program was $947,000 in 2023, and is projected to be $1,505,000 in 2024, $1,955,000 in 2025, and 2,210,000 for the test year ending October 31, 2026, as shown on Exhibit A-58 (MPG-1), line 2. O&M expenses for corrosion control on the transmission system include special projects like large atmospheric painting projects, pipeline recoating projects, shorted casing remediation and close interval surveys. Similar to the capital program (Cathodic Protection – Compression, Storage and Pipeline), O&M projects are typically identified during yearly surveys and typically occur in a short timeframe. The Company's projected expense amount is based on historical averages (100 miles of close interval survey), the re-coating of pipeline sections that have poor coating conditions based on the close interval surveys, and work to clear shorted casings. The projected expense also includes additional atmospheric painting projects at sites that have not been painted in several years and that have had numerous small touch-ups done to prevent corrosion. This additional work will not only allow the Company to continue to meet the regulatory obligations for corrosion control, but also will ensure and enhance the safety of its natural gas delivery systems. These expenses were not projected utilizing inflation factors.

Q. Please describe the Cathodic Compression, Storage, and Pipeline Capital Program.

A. The Cathodic Compression, Storage, and Pipeline Capital Program allows the Company to maintain compliance with federal regulations for cathodic protection of facilities. As shown on Exhibit A-60 (MPG-4), line 3, the capital expenditures for the Cathodic

Compression, Storage, and Pipeline Capital Program were $5,931,000 in 2023, and are projected to be $6,526,000 in 2024, $5,779,000 for the 10 months ending October 31, 2025, and $6,649,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 3, column (b); line 3, column (c); line 3, column (d); and line 3, column (f), respectively. The capital activities included in this program are the installation of new or replacement rectifiers and anode beds, the installation of UT Coupon Test Stations and Remote Monitoring Units ("RMUs"), installation of Alternating Current ("AC") mitigation, the installation of insulators, and installation of permanent UT sensors and coupons for monitoring corrosion rates for its Transmission system. The projects undertaken are identified during yearly routine inspections of the cathodic protection systems. When issues are identified, like pipe-to-soil potentials below criteria, repairs typically must occur within one year of identification. As such, the dollar amounts identified for these programs are based on historical averages. One area that has increased in this program is the installation of AC Mitigation. These projects are intended to mitigate stray AC voltages on the pipeline that can cause corrosion or a shock hazard. Additionally, new rules implemented by PHMSA in 2022 require additional testing and mitigation for possible stray current issues. As a result of these additional requirements, the Company has increased monitoring and identified projects to mitigate stray AC voltages.

C. MAOP COMPLIANCE PIPELINE PROGRAM AND MAOP TRANSMISION PROGRAM

Q. Please describe the MAOP Compliance Pipeline Program.

A. The MAOP Compliance Pipeline Program involves MAOP verification and remediation of the Company's transmission pipelines, including Transmission Operated by Distribution pipelines. This work initially began in 2012, in response to the Pipeline Safety, Regulatory

Certainty, and Job Creation Act of 2011, which required the PHMSA to direct each owner or operator of a natural gas transmission pipeline and associated features to provide verification that their records accurately reflect a pipeline's MAOP. This will improve compliance with state and federal pipeline records requirements and confirm historic system MAOP values. On October 1, 2019, PHMSA published the Safety of Transmission & Gathering Lines Rule which codifies the requirement for MAOP establishing documentation to meet traceable, verifiable, and complete criteria. This rule is also identified starting on page 83 of the SEA, which states:

> In 2016, PMHSA published a proposed rulemaking titled "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" to update 49 CFR Part 192. This proposed rule included significant changes to the transmission integrity management requirements, along with other general changes to transmission and gathering pipelines with enhancements to the following areas:
>
> 1. Re-establishing maximum allowable operating pressure.
> 2. Verifying material properties.
> 3. Performing integrity assessments outside of high-consequence areas.
> 4. Management of change enhancements.
> 5. Corrosion control enhancements.
> 6. Modifying the regulation of onshore gas gathering lines.

Q. How will the Company verify and adequately document the MAOP of these pipelines?

A. This will be accomplished with a detailed engineering analysis or Standardized Engineering Analysis of the Company's Transmission System. The analysis will determine where work is required to meet the traceable, verifiable, and complete criteria, and upgrade the documentation archiving from a historical perspective to a newly developed engineering content management database integrated with the Company's geospatial information system database. The record database will link record files to the data mined from those records and entered into the geospatial information database for

MAOP calculation from those design and testing values. For each transmission pipeline segment identified as not meeting the record criteria established by the newly published rule, the Company will address these segments through an engineering evaluation that will consider the six regulatory methods of MAOP Reconfirmation identified in 49 CFR 192.624 in conjunction with a solution that provides benefits in regard to pipeline safety, reliability, and deliverability. The six methods are:

1. Pressure Test;
2. Pressure Reduction;
3. Engineering Critical Assessment;
4. Pipe Replacement;
5. Pressure Reduction for Pipeline Segments with Small Potential Impact Radius; and
6. Alternative Technology.

Material verification will require a management program for identifying pipeline segments for which the material property value documents necessary to calculate MAOP are not Traceable, Verifiable, or Complete. The management program will provide identification of those segments for when the Company may expose pipe for purposes other than the 49 CFR 192.614 Damage Prevention Program. When exposed, these segments would require either destructive or nondestructive testing to attain material property values. Evaluation is based on an analysis including, but not limited to, the following factors:

- Nature of the records gap identified (e.g., segments with material verification issues prioritized for replacement);
- Pipeline performance history and pipeline field evaluations;
- Minimizing the impact of service to customers;

- Coordination with other planned work and the need to maintain service to customers; and
- Pipeline location and cost to replace (i.e., population density).

Depending upon the work performed, the project would be an O&M expense or a capital expenditure. The Company's MAOP Reconfirmation capital expenditure projections are based on previously completed work orders of similar magnitude and requirements when pipe replacements are performed. As shown on Exhibit A-60 (MPG-4), line 4, the capital expenditures for the MAOP Compliance Pipeline Capital Program were $4,786,000 in 2023, and are projected to be $51,000 in 2024, $2,409,000 for the 10 months ending October 31, 2025, and $3,016,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 4, column (b); line 4, column (c); line 4, column (d); and line 4, column (f), respectively. The projects in 2023 include replacement of piping on Line 1400 underneath Milford Rd and replacement of piping and valves on Line 100A at Mt. Pleasant Station. The capital project planned for 2024 is the retirement of drain piping at the Mt. Clemens City Gate on Line 1060. Capital projects planned for 2025 include the replacement of valves and piping at Metamora City Gate on Line 1900. The Company continues to monitor the gas system for segments without Traceable, Verifiable, and Complete pressure tests to comply with the new PHMSA-published Safety of Transmission & Gathering Lines Rule. Future projects will be identified from the above-mentioned Standardized Engineering Analysis.

Q. Are there any proposals the Company is requesting the Commission to approve that would impact future expenditures in this program?

A. Yes. Company witness Heather L. Rayl describes in her direct testimony a request for the Commission to approve the capitalization of hydrotesting of pipelines, in certain circumstances, to re-confirm the MAOP of these pipelines. The Company does not have any of these projects that would be impacted by this request included in this docket, but anticipates there could be projects in the near future for which it would.

Q. Please describe the O&M expenses related to the Regulatory Compliance - MAOP Transmission Program as shown on Exhibit A-58 (MPG-1), line 1.

A. As shown on Exhibit A-58 (MPG-1), page 1, line 1, the O&M expenses for this program were $1,187,000 in 2023, and is projected to be $1,898,000 in 2024, $2,361,000 in 2025, and $2,370,000 for the test year ending October 31, 2026. The test year O&M expense comprises four parts.

The first part is an annual expense of $489,000 for an Aerial population density survey to fulfill the Federal Regulations within 49 CFR 192, more specifically 49 CFR 192.609 and 49 CFR 192.611.

Second, there are two projects occurring on Line 1500 and two on Line 1900. These projects involve pressure testing the launcher and receiver barrels at St. Clair compression station, Rochester valve site, Grand Blanc valve site, and Atlas valve site to re-establish MAOP.

The third part of the test year expense is an annual expense of $50,000 for Third Party Coordination Surveys. To limit risk, both physically and/or fiscally, this expense will utilize survey data to collect information to determine location (vertical and horizontal) during the pre-planning period. The information gathered through survey data can proactively provide details of Company facilities and will be incorporated into third party plans where potential conflicts can be identified and mitigated prior to the third party construction. This data will primarily be utilized for Asset Relocation projects.

The fourth part of the test year expense is due to expensing the O&M portion of the Standardized Engineering Analysis costs. In 2021, in response to a Staff recommendation in MPSC Case No. U-20650, the Company moved the SEA expenditures to Account 183.2 - Other Preliminary Survey and Investigation Account. The Company is proposing in this proceeding to expense the O&M portion of this account for the 2023 time period, based upon the percentage of orders that resulted in an O&M or capital replacement. The Company proposes to continue the practice of expensing a portion of the Account 183.2 balance in subsequent general rate case proceedings. The capital portion of the account will be allocated to future capital projects. In 2024, the Company expensed $743,971 for the 2022 SEA expenditures. Table 2 below shows the SEA amounts expensed in 2024, and the SEA amount to be expensed in the test year.

Table 2
SEA Expensed in 2024 and the Test Year

Year	Direct Cost	O&M %	O&M Cost
2022	1,323,792	56%	743,971
Amount Expensed in 2024			**$ 743,971**
Year	Direct Cost	O&M %	O&M Cost
2023	1,328,265	85%	1,122,384
Test Year Amount			**$ 1,122,384**

The projects and expenses in 2024 and 2025, for the MAOP Transmission O&M Program and for the test year are shown in Table 3 below. These expenses were not projected utilizing inflation factors.

Table 3

Regulatory Compliance O&M Expenses by Project

Regulatory Compliance - MAOP Transmission O&M Expenses	2025	2026	12 Months Ending Oct 31, 2026
Aerial High Resolution Imagery Survey for Class Location Studies	489,000	489,000	489,000
STC-LN 1060 Mt. Clemens LR Pressure Test	-	369,000	322,875
STC-LN 1060 St. Clair LR Pressure Test	-	341,000	298,375
STC - Line 1500 St Clair LR Pressure Test	350,000	-	43,750
STC - Line 1500 Rochester LR Pressure Test	350,000	-	43,750
3rd Party Coordination Survey Studies	50,000	50,000	50,000
MSEA O&M Projects	1,122,384	1,043,645	1,122,384
Total MAOP Transmission Expense	**2,361,384**	**2,292,645**	**2,370,134**

Company witness Rayl discusses the reduction to rate base for the 2024 amount.

Q. Please explain page 2 of Exhibit A-58 (MPG-1).

A. Page 2 of Exhibit A-58 (MPG-1) presents an illustration of the amounts of the O&M expenses I am sponsoring if one were to apply an inflation rate to the historical O&M expenses. The expenses that I am supporting are based upon the expenses necessary to comply with regulations and improve system safety as described for the programs above, and have not been projected utilizing inflation factors.

III. CAPACITY/DELIVERABILITY PROGRAM

Q. Please describe the capital expenditures relating to the Capacity/Deliverability Program as shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 3.

A. As shown on Exhibit A-12 (MPG-2), Schedule B-5.5, line 3, the capital expenditures for this program were $308,275,000 in 2023, and are projected to be $270,362,000 in 2024, $133,358,000 for the 10 months ending October 31, 2025, and $170,322,000 for the 12 months ending October 31, 2026. These capital expenditures address needed increases in transmission pipeline capacity and ensure measurement accuracy, which help ensure adequate capacity and deliverability throughout the system. These expenditures are driven by projects in TED-I, Deliverability Base Field Measurement, Deliverability Base Pipeline, Regulator Stations – Distribution, and Transmission and Storage ("T&S") City Gates as further described below.

Q. Why are Capacity/Deliverability projects necessary?

A. Capacity requirements can increase due to changes in customer population density in specific locations, and also because of changes in system requirements. Examples of changes in system requirements include the need to support load and maintain pressure (both base and peak day), as well as the need to ensure pipeline configuration to allow for in-line inspection through the Pipeline Integrity Program. Deliverability Program expenditures include city gate and regulation station rebuilds and improvements. This program also includes expenditures for the TED-I projects to ensure continued safe, reliable, and deliverable operation of transmission pipelines. Other project work in this program includes investments to ensure gas quality and gas measurement accuracy. Natural gas quality is critical to ensuring that customers' equipment functions properly and safely. Natural gas measurement accuracy ensures that Consumers Energy is properly measuring and accounting for gas purchased for and delivered to customers, as detailed below.

A. <u>TED-I PROJECTS</u>

Q. Please explain the TED-I projects shown on Exhibit A-61 (MPG-5), line 1.

A. The TED-I projects are focused on maintaining deliverability and integrity, and on improving the ability to control gas flows. As shown on Exhibit A-61 (MPG-5), line 1, the capital expenditures for the TED-I Program were $216,361,000 in 2023, and are projected to be $146,790,000 in 2024, $20,192,000 for the 10 months ending October 31, 2025, and $19,145,000 for the 12 months ending October 31, 2026. Major projects include replacing transmission pipeline segments that contain higher-risk type pipe to ensure integrity and safe operation. In certain cases, city gate stations may be upgraded to enable abandonment of a pipeline or to reduce pressures on pipeline segments to comply with any new MAOP requirements of replacement pipelines. Also included in TED-I are the installation of Remote Control Valves ("RCVs") and Pressure-Limiting Devices ("PLDs") to control pressure and flows during normal operations and in the event of abnormal operation.

Q. Please describe Consumers Energy's investments in its natural gas transmission system as part of the TED-I projects and how they benefit customers.

A. As described in the NGDP, Exhibit A-42 (NPD-1), Section IV.C.2, TED-I pipeline projects improve customer reliability and advance public safety by replacing or retiring higher relative risk pipe segments and, in some cases, increase capacity. Additionally, the replaced pipelines also have enhanced pipeline pressure control and isolation capabilities.

Q. Please explain the TED-I major pipeline projects.

A. TED-I major pipeline projects focus on maintaining integrity and deliverability, and include transmission pipeline replacements of higher relative risk pipe to ensure integrity and safe operation. Higher relative risk pipe includes segments with previous anomalies or stress characteristics related to integrity management risk mitigation. Capacity requirements are factored into line replacements to ensure customer deliverability. The major TED-I construction project included in this filing is the Mid-Michigan Pipeline project which was put into service in 2024.

Q. Please describe the Mid-Michigan Pipeline project.

A. The Mid-Michigan Pipeline project replaced approximately 55 miles of Line 100A, between Ovid City Gate in Clinton County and Chelsea Interchange in Washtenaw County. The project addresses integrity and deliverability concerns with the current pipeline and increase the diameter of the pipeline, from 20-inch to 36-inch within existing pipeline right-of-way ("ROW").

Q. Has the Company received Commission approval to construct and operate the Mid-Michigan Pipeline?

A. Yes. The Commission issued an Order in MPSC Case No. U-20618, on November 19, 2020, approving the Mid-Michigan Pipeline, which authorized Consumers Energy to construct and operate this pipeline.

Q. Please identify capital expenditures for the Mid-Michigan Pipeline.

A. Exhibit A-62 (MPG-6), line 1, identifies the total capital expenditures for the Mid-Michigan Pipeline project. The capital expenditures for this project were $201,391,000 in 2023, and are projected to be $145,589,000 in 2024, $6,935,000 for the 10 months ending October 31, 2025, and $389,000 for the 12 months ending October 31, 2026 (please see Table 4 with detailed expenditures by year). In 2023 through October 31, 2026, projected costs will be incurred for construction, engineering and design, environmental assessment, surveying, and real estate. A summary of this information is provided in the Table 4 below:

Table 4

Mid-Michigan Pipeline Annual Projects & Expenditures

Year	Segment	Length	Projected Spend
2023	Pipeline Construction Phase 1, Additional pipe needed for phases 1 & 2, Stockbridge City Gate & Pleasant Lake City Gate Rebuilds, Long Lead Material Procurement for Phase 2, Engineering, Real Estate, Environmental, Permitting on multiple projects	Approx 30 miles	$201. million (actual)
2024	Pipeline Construction Phase 2, Restoration on Phase 1, Ovid City Gate Rebuild, Engineering, Real Estate, Environmental, Permitting	Approx 25 miles	$146 million (full year projection)
2025	Restoration on Phase 2 and EGLE permitting requirements for wetlands & streams	n/a	$7 million (full year projection)
2026	EGLE permitting requirements & any remaining restoration	n/a	$389 thousand

Major construction commenced in 2023 and concluded in 2024. Site restoration and environmental monitoring will continue beyond 2024.

Q. Why was the Mid-Michigan Pipeline project necessary?

A. The Mid-Michigan Pipeline project is part of the Company's transmission enhancement plan to ensure system safety, integrity, and deliverability. The Line 100A project involved the replacement of 1949 vintage pipe that had demonstrated integrity issues. In May 2015, this line experienced a rupture just north of Chelsea. The project also increased the capacity of the Company's natural gas transmission system. The increased capacity provides a more resilient and flexible system capable of supporting the continued increase in system outage days required by regulatory requirements and other operational maintenance needs.

Q. What other projects are included in the TED-I Program?

A. As described above, also included in TED-I are the installation of RCVs and PLDs to control pressure and flows during normal operations, and in the event of abnormal operation. The installation of these devices is consistent with federal and state guidance. In the SEA, at page 200, the Commission recommended that "utilities continue to conduct analyses to evaluate increasing the number of remote shutoff valve systems in high consequence areas to minimize the impact during emergency events." Further, in April 2022, PHMSA promulgated regulations requiring operators to install automatic shutoff valves or RCVs on new and entirely replaced transmission pipelines as a means of rupture detection and mitigation. Recognizing the significance of these devices, the Company has developed a comprehensive RCV installation plan as outlined in of the NGDP, Exhibit A-42 (NPD-1), Section IV.C.2.

Q. Please explain the RCV expenditures.

A. The Company is planning to install RCVs on complete pipeline replacements, such as Line 100A (Mid-Michigan Pipeline Project). The costs for those RCVs are included in the project expenditures. RCVs are also being installed to reduce response time on certain Class 4 locations and Class 3 locations within HCAs to improve public safety. The costs for those RCVs are included in the Deliverability Base Pipeline Program. The valves do not prevent failures from occurring but are intended to minimize the time gas flows after a failure and any subsequent fire that would prevent emergency first responders from entering the impacted area. RCVs reduce the loss of natural gas should a pipeline failure occur and can be operated remotely by Gas Control for potential reduction in response times. RCVs will not close inadvertently due to load changes, purging activities, or failure of sensing lines. In 2023, the Company installed 37 RCVs and is projected to install 17 in 2024, 17 in 2025, and 16 in 2026. These installation numbers represent all RCVs installed in all programs and projects. Exhibit A-62 (MPG-6), line 3, identifies the total capital expenditures for RCVs not otherwise installed in other programs. The capital expenditures for these RCVs were $2,253,000 in 2023, and are projected to be ($103,000) in 2024, $8,717,000 for the 10 months ending October 31, 2025, and $18,074,000 for the 12 months ending October 31, 2026.

Q. Please explain the reason for the variability in expenditures for RCVs from 2023 to the test year.

A. As explained above, RCVs are also installed in other programs and projects. In 2023, nine RCVs were commissioned (programming and remote testing) but installed in 2022. There were also 18 RCVs installed as part of the Mid-Michigan Pipeline project. In 2024, all of the RCVs installed were either on the Mid-Michigan Pipeline or in the Deliverability Base Pipeline program. In 2025, many of the RCVs are being installed alongside other projects so some of the costs are shared with those projects. In 2026, the majority of RCVs will be stand-alone projects with most of cost being charged to the TED-I program.

Q. Please explain the PLD expenditures.

A. The PLD installation locations are selected pursuant to 49 CFR 192.619 and 49 CFR 192.195. As modification of the Consumers Energy pipeline system occurred due to class location changes, system additions, and purchases over the years, the MAOPs were impacted. Historically, Consumers Energy's Gas Transmission System used pressure drop on pipelines when related to MAOP pressures differences, as outlined within 49 CFR 192.619 and 49 CFR 192.609(e), which states that: "[t]he maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved;". Additionally, Consumers Energy's Gas Control Operations used remotely operated valves for MAOP protection of the Company's system. As technology has advanced, the industry has recognized that a better and safer way to control pressures is through the use of on-site overpressure protection devices using a pressure-regulated monitor valve/worker valve arrangement, commonly referred to as PLDs. These configuration enhancements automate the device and allow for quicker response and improved safety on the gas transmission system. Public safety risk is reduced when PLD equipment is installed, which is reliable and adequately protects against potential over pressurization. The Company continually analyzes the pipeline system for areas where the operational safety of the system should be enhanced. As a result of this analysis, the Company identified a need to install PLDs and established a prudent plan to improve the system and customer safety. The 2023 projects included:

- Line 4060 Vector Hartland, Howell;
- Line 1200A CE-ANR Stag Lake, White Pigeon; and
- Line 2700 Squirrel Rd Valve Site, Lake Orion;

The installation of PLDs improves the operation of the system and provides enhanced public safety. Exhibit A-62 (MPG-6), line 2, identifies the total capital expenditures for PLDs. The capital expenditures for PLDs were $12,156,000 in 2023, and are projected to be ($133,000) in 2024, $0 for the 10 months ending October 31, 2025, and $0 for the 12 months ending October 31, 2026. The PLD installation program was completed in 2024.

Q. What other projects are included in the TED-I Program?

A. Also included in this program are projects that are smaller in scope and related to other TED-I projects that are not RCVs nor PLDs. These include valve site junctions so the Company can use the existing pipelines for outage or other emergent situations and final restoration, property acquisition, and closure of environmental permit requirements related to completed pipeline and other major projects. As part of this program the Company is planning a transmission interconnect with DTE Gas Company in 2025 that will improve overall system resiliency to benefit customers of both utilities. Exhibit A-62 (MPG-6), line 4, identifies the total capital expenditures for Pipeline & Other Installations/ Modifications. The capital expenditures for these projects were $561,000 in 2023, and are projected to be $1,437,000 in 2024, $4,540,000 for the 10 months ending October 31, 2025, and $682,000 for the 12 months ending October 31, 2026.

Q. Please provide further information concerning the transmission interconnect project.

A. The transmission interconnect project, which the Company calls the Oakland Resilience Interconnect, is a project the Company is coordinating with DTE Gas and is for the benefit of both utilities' customers. This project is part of the Company's response to Natural Gas Recommendations for Mitigating Risk, found within the SEA. Once built, this facility will allow either utility to provide natural gas to the other utility to address an emergency, as defined in 18 CFR 284.262, that poses a risk to the ability to provide natural gas service for customers in the State of Michigan. Natural gas supply through this interconnect in response to an emergency will be provided in a best-efforts manner. DTE Gas and Consumers Energy received a certificate of necessity to construct and operate the interconnect through an Act 9 filing on October 10, 2024 in Case No. U-21510. The Commission approved the capital spending for DTE Gas Company's portion of the interconnect in its order in Case No. U-21291 on November 7, 2024. The Company's capital expenditures for this project were $53,000 in 2023, and are projected to be $1,161,000 in 2024, $4,466,000 for the 10 months ending October 31, 2025, and $45,000 for the 12 months ending October 31, 2026. These expenditures are included in the Pipeline & Other Installations/ Modifications expenditures discussed above.

B. DELIVERABILITY BASE FIELD MEASUREMENT PROGRAM

Q. Please describe the Deliverability Base Field Measurement Program investments.

A. The Deliverability Base Field Measurement Program is essential to ensure accurate gas quality and measurement. Exhibit A-61 (MPG-5), line 3, identifies the total capital expenditures for the Deliverability Base Field Measurement Program. The capital expenditures for this program were $5,319,000 in 2023, and are projected to be $6,774,000 in 2024, $10,255,000 for the 10 months ending October 31, 2025, and $19,890,000 for the 12 months ending October 31, 2026. Field measurement projects are associated with remote gas measurement equipment monitoring, gas volume calculations, gas transmission metering, Transport Metering Stations ("TMS"), Interstate Interconnection sites, gas quality improvement and processing, gas sampling systems, and other ancillary equipment. These investments directly impact the Company's ability to conform to the MPSC technical standard requirements concerning natural gas quality, measurement accuracy, and Lost and Unaccounted For ("LAUF") gas. Additional projects in this program include measurement equipment upgrades that allow for improvements in American Gas Association volume calculation algorithms, fuel usage report automation, and transducer replacements. The placement of measurement facilities and equipment at appropriate locations can assist in reducing LAUF gas volumes and improve gas quality monitoring. For additional information on LAUF, please see the direct testimony of Company witness Timothy K. Joyce.

Q. Are there any other activities involved in the Deliverability Base Field Measurement Program?

A. Yes. The Deliverability Base Field Measurement Program also involves the installation of meter facilities to validate delivery volumes from interstate suppliers. These projects help improve measurement accuracy of volumes received. The Company is also installing gas quality and gas processing equipment such as chromatographs and water and hydrogen sulfide analyzers to verify gas received from suppliers or withdrawn from storage meets the requirements of pipeline quality gas in accordance with regulatory requirements. The Company is also planning to construct the Williamston Transmission Meter Proving, Testing, and Development Station in the test year. This station will allow a testing environment for gas transmission measurement technology to comply with API-1164, which requires any new protocol, application, or software proposed to be added to the Supervisory Control and Data Acquisition ("SCADA") network should be run in a test-bed or development environment to evaluate the potential for impairing the performance of the SCADA system. Further, the Transportation Security Administration ("TSA") requires the management of software/credentials on measurement devices and a physical testing laboratory with functional versions of all equipment subject to hardware/firmware upgrades to enable testing/validation of firmware in a controlled/non-production environment. The Company currently does not have a test environment for transmission meters or gas analytical equipment.

Major projects included in this filing include:

- Chelsea Meter Replacement. Project year 2023;
- Summerton Road Gas Quality, valve replacement and metering upgrades. Project year 2023;

- White Pigeon 1200A Meter Installation. Project year 2024;
- Lahser USM Installation. Project year 2025;
- Perry Morrice USM Installation. Project year 2025;
- Laingsburg LN 400 Meter Installation. Project year 2025;
- Grand Blanc LN 500 Meter Installation. Project year 2025;
- Rose Center City Gate Meter Replacement. Project year 2026;
- Northville Line 1200A Meter Installation. Project year 2026;
- Chrysler Tech Meter Upgrade. Project year 2026;
- SCADA Gas Quality Hydraulic Modeling. Project year 2026;
- Eureka City Gate Meter Upgrade. Pre-engineering 2026 and Project year 2027;
- Williamston City Gate Chromatograph Upgrade. Pre-engineering 2026 and Project year 2027;
- Winterfield 12 Chromatograph Upgrade. Pre-engineering 2026 and Project year 2027; and
- Ovid Chromatograph Upgrade. Pre-engineering 2026 and Project year 2027.

C. DELIVERABILITY BASE PIPELINE PROGRAM

Q. Please explain the Deliverability Base Pipeline expenditures.

A. The Deliverability Base Pipeline expenditures support maintaining operations in accordance with the Michigan Gas Safety Standards ("MGSS"). Types of projects include: (i) the replacement of valves, and if necessary, the associated valve operators, when inspection determines that the valves no longer perform as needed, which may mean valves no longer turn or they may not fully seal off the flow of gas (MGSS Rules 192.145, 192.150, 192.179); (ii) the replacement of piping due to MAOP revisions identified as a result of class location changes (49 CFR 192.5 and 192.611); (iii) construction of new sectionalizing valves and tap valves to improve system deliverability, and help meet valve spacing requirements defined by 49 CFR 192.179; (iv) reconfiguration of tap piping (i.e., laterals) and associated valving upstream of city gate facilities as companion projects to city gate rebuilds; and (v) installation or retirement of pipeline taps to TMS facilities being attached to the Company's system. Exhibit A-61 (MPG-5), line 4 identifies the total capital expenditures for the Deliverability Base Pipeline Program. The capital expenditures for this program were $18,757,000 in 2023, and are projected to be $18,173,000 in 2024, $19,403,000 for the 10 months ending October 31, 2025, and $25,023,000 for the 12 months ending October 31, 2026.

Q. Please explain why the Deliverability Base Pipeline expenditures have increased in recent years.

A. The Deliverability Base Pipeline expenditures have increased from historical levels due to a number of factors. In 2019, the Company began conducting annual aerial surveys to enhance the GIS data set to provide more accurate building data along with more accurate occupancy data. There have been a number of class location changes indicated by the aerial survey. Per 49 CFR 192.611, these are segments of pipeline that need to be replaced within 24 months of the change in class location in order to operate the pipeline under the published MAOP. These segment replacements are included in the projection for this program.

Secondly, the Company began conducting annual system wide valve spacing studies in 2021 that review each Transmission Pipeline segment against the current class location to determine if the pipeline segments are in compliance with 49 CFR 192.179. These studies identify the valve(s) required to be compliant with 49 CFR 192.179.

D. REGULATOR STATIONS - DISTRIBUTION

Q. Please describe the regulator station investments.

A. Distribution regulator stations reduce pressure supplied from a higher pressure distribution system to another with a lower pressure distribution system. For example, a regulator station could be used to supply a medium pressure (60 psig MAOP) system from a high pressure system (400 psig MAOP). Exhibit A-61 (MPG-5), line 5, identifies the total capital expenditures for the Regulator Station Program. The capital expenditures for this program were $36,262,000 in 2023, and are projected to be $45,690,000 in 2024, $36,039,000 for the 10 months ending October 31, 2025, and $47,274,000 for the 12 months ending October 31, 2026. The scope of the expenditures in this program is aimed at maintaining the integrity of 648 regulator stations. Additional benefit is realized by the modernization of the fleet of regulator station through the reduction of unintended methane emissions. The Company's regulator station installation plan is further described in Section IV.D.6 of the Company's NGDP, Exhibit A-42 (NPD-1), sponsored by Company witness Dreisig. The Company currently has 94 odorizers, which are considered distribution assets funded as part of this program as well, despite the fact that they are often co-located at city gate sites. These odorizers add odor to the downstream gas systems, which is a critical safety element and is required by code (49 CFR 192.625). Planned projects, location, and project type are listed below. This program also funds emergent issues, as well as SCADA installations, retrofitting of existing gas heaters with modern burner management systems ("BMS"), installation of slam-shut overpressure protection devices and electrical improvements at regulator stations. Investments being made to regulator stations improve employee safety and ergonomics. Regulator stations located in pits may be difficult to enter and pose risk for operators. These projects are selected based on discussions with subject matter experts and major stakeholders, which include Operations and Engineering, but are also based on asset performance and age of the facility. The major projects in this filing include:

2023

- Verlinden & Shiawassee (Rebuild -Lansing);
- Montrose & Ridgeway (Rebuild – Mount Morris Twp);
- Riverside Dr. (Rebuild – Ionia);
- 21st & Jefferson (Rebuild – Bay City);
- Columbus & Trumbull (Rebuild – Bay City), Functional replacement of 10th & Trumbull;
- Cedar Lake (Rebuild – Day Twp);
- Marshall-Butterfield (Rebuild – Olivet);
- Chicago & Ballenger (Rebuild – Flint); and
- St. Clair Line 1060 distribution odorizer (Rebuild – Ira).

2024

- 21 Mile & Romeo Plank Rd. (Rebuild – Macomb Twp);
- Selfridge – Rosso Hwy. (Rebuild – Mt. Clemens);
- Ithaca Reg Station (Rebuild – Ithaca);
- State & Hemmeter (Rebuild – Saginaw);
- Grand River & Mechanic (Rebuild – Williamston);
- Lake Lansing & Rutherford (Rebuild – East Lansing);
- Attica & Lake Pleasant (Rebuild – Attica Twp); and
- Plainwell Valve Site Odorizer (Rebuild – Plainwell).

2025

- Hotchkiss & M-84 (Rebuild – Bay City);
- Poseyville (Rebuild – Midland);
- Center & Boltwood (Rebuild – Hastings);
- Hogsback & Pryor (Rebuild – Mason);
- Sheridan & Lansing (Rebuild – Gaines Twp.);
- Silver Lake & Dixie (Rebuild – Waterford Twp.);
- Gardner & 7 Mile (Rebuild – Northville); and
- Clintonia Rd. Valve Site Odorizer (Rebuild – Danby Twp.)

2026

- Pitcher & Lovell (Rebuild – Kalamazoo)
- Shepherd & Horatio (Rebuild – Charlotte)
- Sohn Rd. Regulator St. (Rebuild – Vassar)
- Corunna Ave. Regulator St. (Rebuild – Corunna)
- Corunna & M-71 (Rebuild – Corunna)
- Oakland & Sarasota (Rebuild – Pontiac)
- Ruth & Atwater (Rebuild – Ruth)
- Central Odorant Operations Hub (Odorant storge facility – Mid-Michigan).

E. T&S CITY GATES

Q. Please further describe the T&S City Gate investments.

A. City gate stations are the delineation point between the transmission and distribution systems. Gas pressure is reduced to distribution pressure, often 400 psig or less, through pressure regulation. Over-pressure protection, including relief valves, monitor regulators, or emergency shutdown valves (ESD) are installed at these locations to ensure a safe limit to pressure in the distribution system exists. Odorizer stations are often installed at city gates; although these are distribution assets, they are co-located due to Federal code requirements (49 CFR 192.625) to odorize distribution systems. Odorizers are funded in the Regulator Station Program unless they are installed as part of a complete city gate rebuild. Exhibit A-61 (MPG-5), line 6, identifies the total capital expenditures for the T&S City Gate Program. The capital expenditures for this program were $31,320,000 in 2023, and are projected to be $52,913,000 in 2024, $47,469,000 for the 10 months ending October 31, 2025, and $58,991,000 for the 12 months ending October 31, 2026. The scope of the city gate program allows for the rebuilding or other improvements to existing city gate facilities to ensure system reliability and in response to increased customer load demands. City gate stations allow for certain system safety controls during critical system incidents. City gates can have set pressures lowered or increased to restrict flow into the distribution system, allowing for a greater degree of security, redundancy, and resiliency. Valves, including installation of over pressure protection such as an Emergency Shut-Down Valve ("ESD"), can also be closed to restrict delivery as a mitigation if serious situations develop and to prevent an MAOP exceedance. The Company has developed a city gate work plan as outlined in Section IV.C.2 of the Company's NGDP, Exhibit A-42 (NPD-1). As identified in the NGDP, many city gates are 40 to 50 years old. This makes it challenging to acquire parts and rebuild material for the critical equipment located within the city gate. These projects are selected based on discussions with subject matter experts and major stakeholders, which include Operations and Engineering, but are also based on asset performance and age of the facility. This program also includes expenditures for heater and separator reliability projects. Additionally, this program funds remote terminal units ("RTU") and electrical improvements at transmission sites, which include replacing or updating RTUs, safety measures associated with lighting, gas detection, or security, and other modernization electrical and instrumentation efforts. Obsolete programming logic controllers also require replacement due to being unsupported and reaching the end of their manufactured recommended life. Many of the City Gates contain this legacy equipment which will need to be updated to modern equipment to prevent downtime in the event of a failure. As emergent projects arise, priority is given to the most important to help ensure safety and reliability, which can result in deferring a planned project. The major city gate projects in this filing include:

2023

- Akron City Gate (Rebuild - Akron);
- Galesburg City Gate (Rebuild – Galesburg);
- Kalamazoo – M Ave City Gate (Rebuild - Kalamazoo); and
- Pontiac Walton ESD (Auburn Hills).

2024

- Excelsior City Gate (Pipe install and City Gate Retirement - Excelsior);
- Orion City Gate (Rebuild - Lake Orion);
- Leonard-Lakeville City Gate (Rebuild – Leonard);
- Blissfield Panhandle Eastern Pipeline ("PEPL") City Gate (Rebuild - Blissfield);
- Dorr City Gate (Partial Rebuild & Modernization - Dorr);
- Jackson Park Rd City Gate (ESD Installation & Electrical Upgrade) - Jackson); and

- Laingsburg City Gate (ESD Installation & Electrical Upgrade - Laingsburg) ;

2025

- Bancroft City Gate (Rebuild - Morrice);
- Lahser City Gate (ESD Installation & Electrical Upgrade - Beverly Hills);
- Flint Torrey City Gate (Rebuild - Flint);
- Macomb City Gate (ESD Installation & Electrical Upgrade - Macomb)
- Hanover Horton City Gate (Rebuild);
- Jackson Hart PEPL City Gate (Rebuild);
- Highland City Gate and odorizer (Rebuild); and
- Overisel Compression (Electrical Upgrade)

2026

- Novi-Wixom City Gate (ESD Installation and modernization);
- Spring Arbor PEPL City Gate (Rebuild);
- Flint CG Irish Rd City Gate;
- Dixie Waterford (ESD Installation & Electrical Upgrade);
- Climax City Gate (Rebuild);
- South Lyon – Whitmore Lake City Gate (Rebuild);
- Mendon Leonidas City Gate (Rebuild); and,
- Northville Compression (Electrical Upgrade)

F. <u>MISCELLANEOUS TRANSMISSION AND COMPRESSION</u>

Q. Please explain the Miscellaneous Transmission and Compression Expenditures shown on line 2 of Exhibit A-61 (MPG-5).

A. This line represents legacy expenditures in programs no longer used, and final settlement costs for projects as they are closed out. In 2023 and 2024, the expenditures are for legacy program costs related to measurement and regulation projects.

Q. Are there contingency costs included in these capital expenditures?

A. No. Although it is a common and prudent practice to include project contingency costs for these types of projects, and is recognized as an accepted Project Management practice, especially when contingency covers the expansion of work approved, contingency costs have not been included in these projections. While contingency costs are a real item in a project estimate, like any other cost, and should be included in estimates of major projects, due to past Commission orders concerning the inclusion of project contingency, the Company has not included those costs in this filing.

Q. Please describe Exhibit A-63 (MPG-7).

A. Exhibit A-63 (MPG-7), in accordance with Attachment 11 to the filing requirements prescribed in Case No. U-18238, provides the variances in the capital program amounts for the distribution and transmission programs, which I sponsored in the Company's most recent general gas rate case, Case No. U-21490.

Q. Can you explain why columns (c), (d), (e), and (f) of Exhibit A-63 (MPG-7), do not contain any data?

A. Yes, the information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-21490," cannot be provided because Case No. U-21490 resulted in a settlement agreement that did not specifically state approved capital spending amounts for the programs I am supporting. Thus, column (c), the "Last Approved Spending Plan" cannot be calculated. Since there is no data to display in column (c), the information for columns (e) and (f) that seek information concerning the variances from (c), cannot be completed. As for the information for column (d), the "Actual Spending in the Test Year," cannot be completed as the test year in Case No. U-21490, which was the 12 months ending September 30, 2025, is a time period that has yet to transpire as of the filing of this case.

Q. Can you summarize your direct testimony?

A. Yes. The three programs described in my direct testimony span the major areas of Gas Transmission and Distribution operations. These programs eliminate depth of cover issues and physical conflicts with other utilities to ensure continued safe operation, ensure MAOP verification and remediation of the Company's transmission pipelines, and address needed increases in transmission pipeline capacity, all of which help to ensure adequate capacity and deliverability throughout the system. These investments will help the Company meet its objectives of supplying safe, reliable, affordable, and clean energy to customers as described in the NGDP.

Q. Does this complete your direct testimony?

A. Yes, it does.

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	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

KENDRA K. GROB

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Kendra K. Grob, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your current position with Consumers Energy?

A. I am currently the Senior Manager, Benefits.

Q. What are your responsibilities as Senior Manager, Benefits?

A. I am responsible for design, implementation, and administration of the Company's retirement and health care plans and our department has responsibility for the benefit plans for employees and retirees. In the retirement benefits area, the Company contributes to the cost of the Pension Plans, the Defined Company Contribution Plan ("DCCP"), and the 401(k) Employees' Savings Plan ("ESP"). My responsibilities for these benefit plans include the design, review, and administration of competitive, cost-effective, quality plans that will attract and retain qualified employees to serve customers. The purpose of these plans is to provide a portion of an employee's retirement income along with the employee's social security benefits and personal savings.

In the benefits area, the Company contributes to the cost of these benefits plans – health care (medical/prescription drug/dental including Health Savings Accounts ("HSAs") and Health Care Flexible Spending Accounts ("HCFSAs"), life insurance, and Long-Term Disability ("LTD") insurance. Like the retirement plans, our department also has responsibilities for these health care and other benefit plans to include the design, review, and administration of competitive, cost-effective, quality plans for employees and retirees of the Company that help attract and retain qualified employees to serve customers. In addition to these plans, the Company has the responsibility for several additional benefit plans offered to employees by the Company at group discounted rates, which require the employee to pay the full cost of the coverage elected. These voluntary plans include accidental death and dismemberment insurance, health care and dependent care flexible spending accounts, vision insurance, and dependent term life insurance. In 2024, the Company added hospital indemnity, critical illness, and accident benefits. These insurance benefit plans help attract and retain qualified employees to serve customers as these plans help protect employees and their families from significant financial loss in a number of areas. Our team is also responsible for Absence Management, Workers' Compensation, and Occupational Health programs, as well as the total well-being program, Live Well 365, which motivates employees to manage their entire well-being.

Q. What is your formal educational experience?

A. In 1998, I graduated from Siena Heights University in Adrian, MI with a Bachelor of Business Administration degree. I hold a Professional certification in Human Resources from HR Certificate Institute ("HRCI") and the Society of Human Resource Management ("SHRM").

Q. Would you please describe your previous work experience?

A. In 1995, I began my career focused on human resources at Health Care Solutions, Inc. as a Human Resources Manager. In this role, I was responsible for the Human Resource Management of the corporate office in Ann Arbor, MI. Also, I had leadership responsibility over all field Human Resource Managers. In addition to this responsibility, I managed all health care and retirement plans for the company. It was my sole responsibility to ensure employees were enrolled in the correct plans and provide any administration to the plan. This also included plan audits and decision making in determining the best vendors.

In 2007, I began working for Amcor Rigid Packaging as a Senior Benefits Specialist. My area of responsibility was retirement plans, disability, and life insurance plans. In this role, I was responsible for the relationship with vendors and the administration of plans for our employees. I was the primary vendor contact for these areas and was heavily involved in all Request for Proposal processes in choosing vendors. While in this position, I sat on the Retirement Committee as the Secretary and took part in plan design and fund selections for both the pension and the savings plan.

In 2020, I joined Consumers Energy as Manager, Retirement Plans. My responsibilities included complete oversight for the Company pension and savings plans (401k). In this role, I ensured the Company provides retirement benefits to active and retired employees while maintaining accurate legal compliance with the Internal Revenue Service.

In March 2024, I was promoted to Senior Manager, Benefits. In this role I continued complete oversight for the Company pension and savings plans (401k) with the addition of assuming responsibility for health and welfare benefits.

Q. Are you a member of any professional societies or trade associations?

A. I am professionally certified as a Human Resources Professional through both SHRM and HRCI.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide support for the Company's costs related to the gas business portion of retirement, health care, life insurance, LTD plans, and other benefits provided to its employees and retirees. In Part I of my direct testimony, I will address the retirement benefits plans. In Part II of my direct testimony, I will address health care, life insurance, LTD plans, and other benefits, which include absence management and educational assistance programs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-64 (KKG-1)	Summary of Actual and Projected Benefits O&M Expenses for the Year 2023 and Test Year Twelve Months Ending October 31, 2026;
Exhibit A-65 (KKG-2)	CMS Energy – Pension Plans A and B - ASC 715 Pension Expense Estimates ($ millions);
Exhibit A-66 (KKG-3)	CMS Energy - ASC 715 OPEB Expense Estimates ($ millions); and
Confidential Exhibit A-67 (KKG-4)	CMS Energy – Actuarial Letter of Support for 2024 Year Projections.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please describe Exhibit A-64 (KKG-1).

A. Exhibit A-64 (KKG-1), page 1, summarizes 2023 actual expenses through the 12 months ending October 31, 2026, projected gas Operating and Maintenance ("O&M") expenses for the Company's retirement and insurance benefit plans offered to employees and retirees. On this exhibit, column (a) provides a program description of the O&M expense category. Column (b) provides the actual expense in 2023 for each plan. Column (c) provides the projected expense for the 12 months ending October 31, 2026. Page 2 provides information on inflation factor projections and adjustments using the methods discussed in this testimony and included in column (i). Column (j) is the projected test year O&M expense and is the sum of columns (b) + (d) + (f) + (h) + (i).

Q. Please describe Exhibits A-65 (KKG-2) and A-66 (KKG-3) and Confidential Exhibit A-67 (KKG-4).

A. Exhibits A-65 (KKG-2) and A-66 (KKG-3) provide the Aon actuarial projections for Pension and Other Post Employment Benefit ("OPEB") expenses for the years identified. Both the Pension and OPEB projections in these exhibits provided by the Aon actuaries are from the year-end 2023 measurement of the Pension and OPEB plans and with current market conditions as of December 31, 2023. A letter from the actuary regarding the accuracy and completeness of the projections is included in Confidential Exhibit A-67 (KKG-4).

I. RETIREMENT BENEFITS PLANS

Q. Which retirement benefits are you addressing in this section of your direct testimony?

A. I am addressing the Pension Plans, DCCP, and ESP. These expenses are shown on Exhibit A-64 (KKG-1), page 1, lines 1 through 3.

Q. How are the Pension Plans, DCCP, and ESP expenses that are common to electric and gas operations allocated to the gas portion of the business?

A. Expenses common to both the electric and gas operations associated with the Pension Plans, DCCP, and ESP are allocated based on the relationship of employee labor dollars charged to gas operations compared to the labor dollars charged to both electric and gas operations. These allocations are made by the Accounting Department. The gas portion of the O&M expense for these plans is shown on Exhibit A-64 (KKG-1), page 1.

Pension Plans

Q. Would you please explain your Exhibit A-64 (KKG-1), line 1, which begins with ($28,482,000) in 2023?

A. Exhibit A-64 (KKG-1), page 1, line 1, shows the actual 2023 pension expense and the projected expense for 12 months ending October 31, 2026, attributable to the gas portion of the utility operations.

Q. How does the Company determine its expense for the Pension Plans?

A. The pension expense is determined using actuarial analysis that is performed in accordance with Accounting Standards Codification ("ASC") 715. Consumers Energy follows Generally Accepted Accounting Principles ("GAAP") for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodology and assumptions required to properly calculate and account for pension expense which includes evaluation of market conditions at each of the Pension Plan's measurement dates. In addition, the Company's auditor rigorously reviews the process to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of pension expense. Pension expense is determined based on actuarially reviewed employee census data, plan provisions, plan assets, and certain other assumptions. Year-end disclosure information is also produced, based on these accounting standards, to show a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this gas rate case, the Pension Plans were measured in January for year-end December 31, 2023.

Q. What are the components of the annual pension expense under ASC 715?

A. There are four components of the annual pension expense: (i) service cost; (ii) interest cost; (iii) expected return on plan assets; and (iv) amortization of gains or losses, prior service costs or credits, and any transitional amounts. The plan's service cost represents the value of the benefits earned during the year. This is determined individually for each participant based on their specific employee demographics. The interest cost represents interest on the plan's liabilities due to the passage of time. There is also an assumption made for the expected return on plan assets. The expected return on plan assets each year reduces the plan's annual expense. The expected return assumption is reviewed periodically by the plan's actuary, the plan's investment advisor, and the Company, and is intended to be a long-term assumption based on the best estimate of the long-term expected investment earnings of the plan assets. The last component of plan expense is amortization of various plan experiences that were not anticipated by the plan's actuarial assumptions. For example, plan experience gains or losses and plan design changes that would be amortized are included as a part of this component of plan expense. The amortization can be either credits or costs.

To calculate the plan's total pension benefit obligation and annual ASC 715 expense, the actuary uses a number of assumptions including discount rate, mortality table, salary change, expected return on plan assets, and expected future contributions needed to avoid benefit restrictions under the Pension Protection Act. The methods used to set assumptions are generally unchanged annually, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary.

Q. Please describe how the discount rate is set each year.

A. The Company relies on its actuary's discount rate setting model. The model uses current high-quality bonds to match the Pension Plan's cash flows using statistical techniques that create a yield curve that determines the effective discount rate for all maturities of pension payments. The model itself does not change annually, but the discount rate typically will be updated based on the most current market conditions.

Q. Please describe how the expected return on plan assets is set each year.

A. The Company uses future expected capital market assumptions, asset allocation information, and other resources provided by its consultants, which may include survey data and analysis of the Pension Plan's asset allocation. The expected return assumption is based on long-term expectations and not short-term returns. The Company uses all this information to establish an expected return on plan assets assumption that best estimates its expectation. While this assumption is reviewed for each plan measurement, it may or may not be updated annually depending on the information that is presented.

Q. Does the Company apply Accounting Standard Update ("ASU") No. 2017-07 Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this case?

A. Yes, the Company adopted the ASU No. 2017-07 standard as of January 1, 2017, and has applied the Standard in this case for both Pension and OPEB. This ASU No. 2017-07 standard allows only the service cost component of expense to be recorded as an operating expense and all other benefit-cost components are to be recorded outside operating income. The Standard also allows only service costs to be capitalized, while all other cost components are recorded to net income immediately.

Q. Please describe the development of the Pension Plans' expense shown on Exhibit A-64 (KKG-1), page 1, line 1, which begins with ($28,482,000) for 2023.

A. The annual pension expense shown on Exhibit A-64 (KKG-1), page 1, line 1, for the gas utility is based upon Aon's actuarial determination of each plan's total expense for that year in accordance with ASC 715 and includes plan administration fees, aggregated for total pension expense. The Consumers Energy pension expense determined by Aon plus administration fees are allocated to the electric and gas portions of the utility using the Accounting Department methodology described earlier. This allocation resulted in the actual gas utility O&M expense for Pension of ($28,482,000) in 2023, and projected expense of ($34,801,000) for the 12 months ending October 31, 2026. Exhibit A-64 (KKG-1), page 2, line 1, column (i), compares the Aon actual calculation of expense with the 2023 actual expense, as adjusted for 2024, 2025, and 2026 inflation, to calculate other adjustments.

Q. Have there been any significant changes to the Pension Plan structure in recent years?

A. Yes. The Company split its Pension Plan into two plans as of January 1, 2018. Generally, all participants who were employees of the Company on August 1, 2017, were included in Pension Plan A. All other participants, including any Cash Balance participants, were assigned to Pension Plan B. No changes to participant benefits occurred because of this change. The Company decided to make this change to help manage expenses of the Pension Plans by extending the amortization period for the inactive group and enabling the mitigation of Pension Benefit Guarantee Corporation premium variability.

Q. Did the Company make any cash contributions to the Pension Plans in 2023?

A. No, the Company did not contribute to either plan in 2023.

Q. Will the Company make any cash contributions to the Pension Plans in 2024?

A. No cash Pension Plan contributions are required in 2024 to avoid benefit restrictions. Any contributions the Company elects to make during these periods of time will depend upon future decisions of the Company regarding funding policy, the future value of plan assets and liabilities, and any potential legislative guidance or changes.

Q. Why did the pension expense decrease for the projected test year from 2023?

A. The Pension expense decreased due to higher-than-expected asset returns in 2023.

Q. Have any changes recently been made to the Pension Plans' benefits?

A. No significant benefit changes have been made to the Pension Plans since September 1, 2005, when the Pension Plans were closed to new hires and the DCCP was implemented for new hires. Increases in pension expense created by the assumption changes are moderated by the closure of the Pension Plans to new hires as of September 1, 2005. In addition, pension liabilities and expenses are moderating overall as many participants are retiring or leaving and commencing their benefits, which reduces the liability and associated expense over time. Liability and expense will continue to diminish (presuming no significant change in the market or discount rates) until there are no longer any employees or retirees covered by the defined benefit ("DB") Pension Plans.

Effective November 1, 2020, the Company changed the unreduced early retirement age from 62 to 61 for the Company's pension union eligible employees. This benefit enhancement allows for the Company to continue to retain current union pension eligible employees since they can now retire one year earlier but not lose any percentage of their pension benefit and was very well received. The additional changes in the projected pension expense estimates from 2023 to the 12 months ending October 31, 2026, are primarily the result of economic conditions external to the Pension Plans over which the Company has no control.

DB Pension/OPEB Volatility Mechanism ("VM")

Q. Please describe the DB Pension/OPEB VM that the Company is proposing.

A. The Company requests the ability to continue its implementation of a DB Pension/OPEB VM that the Company was authorized to implement in the Commission's settlement agreement in Case Nos. U-21490 and U-21308. The sensitivity of DB Pension/OPEB expenses to changes in asset returns or other assumptions creates a significant potential for large variability in future expenses. Customers benefit from a mechanism that eliminates the risk of future volatility in expense. Without a mechanism, there could be substantial, unanticipated swings in the DB Pension/OPEB expense. The proposed mechanism, which mirrors the mechanism that has existed since October 2023, would protect customers from this volatility by allowing the Company to defer annually the difference between the DB Pension/OPEB expense included in rates versus the actual annual DB Pension/OPEB expense recorded by the Company pursuant to ASC 715.

Q. Is the mechanism symmetrical?

Yes. Under the mechanism, if the actual annual DB Pension/OPEB expense is less than the expense approved in rates, the difference would be recognized as a regulatory liability and amortized over 10 years starting the following January. Similarly, if actual annual DB Pension/OPEB expense is greater than the expense approved in rates, the difference would be recognized as a regulatory asset and amortized in the same manner. Any amortization of these regulatory assets or liabilities would be included in future general rate cases. The mechanism is not only fair; similar mechanisms have been approved by the Commission for other utilities in contested cases. See, e.g., MPSC Case No. U-20836, November 18, 2022 Order, pages 291-292; MPSC Case No. U-20940, December 9, 2021 Order, page 154.

Q. Please describe the Pension VM Deferral on Exhibit A-64 (KKG-1), page 1, line 7, column "b", which begins with $(266,000) for 2023.

A. Per the Settlement Agreement in Case No. U-21308, the Company was authorized to defer actual DB Pension expense different than the approved amount of ($29,547,000) starting October 1, 2023. In 2023, the DB Pension expense was higher than the approved 12-month amount as shown on Exhibit A-64 (KKG-1), page 1, line 1, column b, of ($28,482,000) for October 1, 2023 to December 31, 2023. The Company compared the three months of authorized $7,386,750, taking the 12-month authorized $29,547,000 dividing by 12 and times by three for the three months October 1, 2023 to December 31, 2023. The Company recorded the difference between the actual DB Pension expense and the approved rate expense for the Pension VM for that time period. The Pension VM of ($266,000) resulted in a decreased expense for 2023, and the Company consequently recorded a Pension VM regulatory asset for $266,000.

Q. Please describe the Pension VM Amortization on Exhibit A-64 (KKG-1), page 1, line 9, column "c", which begins with ($791,000) for 12 months ending October 2026.

A. The Pension VM amortization includes the deferred amounts being amortized for the years 2023 to 2025. The deferred Pension VM is being amortized over 10 years which is consistent with how the VM settlement in Case Nos. U-21490 and U-21308 will operate.

Q. Please describe the OPEB VM Deferral on Exhibit A-64 (KKG-1), page 1, line 8, column "b", which begins with ($31,142,000) for 2023.

A. Per the Settlement Agreement in Case No. U-21308, the Company was authorized to defer actual OPEB expense different than the approved amount of ($31,142,000) starting October 1, 2023. In 2023, the OPEB expense was lower than the approved 12-month amount as shown on Exhibit A-64 (KKG-1), page 1, line 5, column b, of ($33,761,000) for October 1, 2023 to December 31, 2023. The Company compared the three months of authorized $7,785,500 taking the 12-month authorized $31,142,000 dividing by 12 and times by three for the three months October 1, 2023 to December 31, 2023. The Company recorded the difference between actual OPEB expense and approved rate expense for the OPEB VM for that time period. The OPEB VM of $655,000 resulted in an increased expense for 2023, and the Company consequently recorded an OPEB VM regulatory liability for $655,000.

Q. Please describe the OPEB VM Amortization on Exhibit A-64 (KKG-1), page 1, line 10, column "c", which begins with ($1,423,000) for 12 months ending October 2026?

A. The OPEB VM amortization includes the deferred amounts being amortized for the years 2023 to 2025. The deferred OPEB VM is being amortized over 10 years which is consistent with how the VM settlement in Case Nos. U-21490 and U-21308 will operate.

DCCP

Q. Does the Company provide an alternative qualified benefit plan to the closed Pension Plans for employees hired on and after September 1, 2005?

A. Yes. In order to remain competitive by offering a benefits package that attracts and retains qualified and talented employees for the benefit of the customer, the Company replaced the Final Average Pay and Cash Balance versions of the qualified DB Pension Plan with the qualified DCCP for all existing Cash Balance participants and newly hired employees on and after September 1, 2005.

Q. Are there any employees included in the DCCP that were hired before September 1, 2005?

A. Yes. Those employees who were hired between July 1, 2003, and August 31, 2005, and were provided coverage under the Cash Balance version of the DB Pension Plan became participants in the DCCP as of September 1, 2005. At the same time, for this specific group of employees, additional pay credits under the Cash Balance version of the DB Pension Plan were discontinued.

Q. Will the Cash Balance version of the DB Pension Plan accept any new employees as participants?

A. No. As with the Final Average Pay DB Pension Plan, the Cash Balance version of the DB Pension Plan now has a finite group of participants that, over time, will diminish until there are no longer any employees or retirees covered under this plan.

Q. Please provide a general description of the DCCP.

A. The DCCP currently provides an employer funded cash contribution as a percentage of an employee's base pay to the ESP—the percentages vary with years of service as described below. No employee contribution is required to receive the employer contribution. All existing Cash Balance Plan employee participants and employees hired on and after September 1, 2005, participate in the DCCP as part of their retirement benefit package.

Q. Have any recent changes been made to the DCCP?

A. No changes have been made to the DCCP since 2021. Effective January 2021, for the Company's union employees, the DCCP provides an 8% to 10% (previously 5% to 7%) employer funded cash contribution based upon the union employee's service time with the Company. New union hires receive an 8% contribution, which increases to 9% when they have six years of service with the Company. When union employees reach 12 years of service, they receive a 10% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism. The increase in the union DCCP contributions was needed for the Company to remain competitive to attract qualified employees and retain talent that maximizes the efficiency of the Company's labor force and reduces costly turnover. Retaining trained, experienced, and motivated employees provides better service for customers.

The Company's exempt and non-exempt employees will continue to receive the DCCP which was effective in January 2016. The DCCP provides a 5% to 7% (previously 6%) employer funded cash contribution based upon the employee's service time with the Company. New hires receive a 5% contribution, which increases to 6% when they have six years of service with the Company. Employees receiving a 6% contribution before January 1, 2016, continue to receive their 6% employer contribution. When employees reach 12 years of service, they receive a 7% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism and helps contain the cost of the DCCP for the benefit of the customer as all new hires starting in 2016 began receiving a 5% (previously 6% for new hires) employer contribution.

Q. Would you please explain your Exhibit A-64 (KKG-1), page 1, line 2, which begins with $7,952,000 in 2023?

A. Exhibit A-64 (KKG-1), page 1, line 2, represents the gas operations O&M expense related to the DCCP. The actual gas operations expense for this plan in 2023 was $7,952,000 as shown in column (b). Column (c) shows the projected gas DCCP expense of $8,155,000 for the 12 months ending October 31, 2026. DCCP costs are projected to increase using inflation factors of 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026. If a DB Pension individual retires, the new person hired to replace their role is entered into the DCCP plan. For the projected years 2024 thru the 12 months ending October 31, 2026, costs were split using 61% electric and 39% gas, with 61% capital on gas expenses.

Q. As a result of the revised eligibility requirements for participation in the Final Average Pay DB Pension Plan or the Cash Balance version of the DB Pension Plan, is it correct to say that all new hire employees who started on September 1, 2005, and after will receive their retirement benefits through plans that are referred to as defined contribution type plans?

A. Yes. The primary plans that will provide monetary benefits to this group of employees upon retirement are the DCCP and the ESP.

ESP

Q. Please explain briefly the ESP.

A. The ESP is a defined contribution retirement savings program funded by employee and employer contributions. A portion of employee contributions is matched by Consumers

Energy. Prior to January 2022, the Company matched 100% of the employee's first 3% in contributions and 50% of the employee's next 2% in contributions to the ESP. Employee contributions beyond 5% were not matched by the Company. Consumers Energy's expense includes the Company's matching contributions, and the payments made to Fidelity Investments for administration of the program.

Q. Have any recent changes been made to the ESP?

A. Effective in January 2022, the Company match design has changed only for Salaried (exempt and non-exempt) employees to 100% of employee contributions up to 6% of the employee's salary. Employee contributions beyond 6% will not be matched by the Company. This change will help to keep the ESP cost and talent retention competitive in the market for the benefit of customers. The Union employees will continue receiving matching contributions of 100% for employee contributions of up to 3% of the employee's salary, and then 50% of employee contributions up to the next 2% of the employee's salary.

Q. Would you please explain your Exhibit A-64 (KKG-1), page 1, line 3, which begins with $6,449,000 in 2023?

A. Exhibit A-64 (KKG-1), page 1, line 3, represents the Company's gas operations expense related to the ESP. In 2023, the actual gas utility O&M expense for the ESP was $6,449,000. The gas utility's ESP O&M expense projected for the test year is $6,615,000. Savings Plan costs are projected to increase using inflation factors of 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026. For the projected years 2024 through the 12 months ending October 31, 2026, costs were split using 61% electric and 39% gas, with 61% capital on gas expenses.

Q. Is the ESP employer matching program important to attracting and retaining employees?

A. Yes.

Q. Please explain why the ESP employer matching program is important to attract and retain employees.

A. The ESP with a match is commonly available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company, particularly considering the large number of retirement-eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Safe, reliable, and affordable gas service begins and ends with the Company's people. Investing in and retaining trained, experienced, and motivated employees' benefits customers as much as, or more than, any investment in infrastructure.

Q. Is the ESP employer match discretionary?

A. It is not discretionary for union employees. A provision in the Working Agreement ratified in 2005 with Operating Maintenance & Construction ("OM&C") and Virtual Call Center ("VCC") union employees assured these employees that the match would not be suspended during their five-year contract. This provision was renewed in the 2010 contracts as part of the final union agreements for these union groups, and it is also part of the Steelworker's union contract effective January 1, 2011. This provision was not changed in the most recent five-year contracts negotiated in 2020. This has been a prominent issue for the union during the last several labor negotiations, all of which were finally resolved through arms-length bargaining.

With respect to non-union employees, there is not a similar contractual prohibition against suspension. However, the ESP employer match is part of an overall competitive benefits package and employees depend upon its continuation so they can accumulate savings for retirement. The Company's competitors continue to offer a savings plan match, and the Company plans to continue offering the match to compete for new talent and retain current talent for the benefit of the customer. As noted above, it is a benefit that helps the Company attract and retain qualified and talented employees. From a practical standpoint, the Company views the employer match as non-discretionary.

II. HEALTH CARE, LIFE INSURANCE, LTD PLANS, AND OTHER BENEFITS

Q. Which health care and insurance benefits are you addressing?

A. I am addressing active employee health care (including HSAs and HCFSAs), life insurance, LTD plans, and other benefits of absence management and educational assistance, as well as retiree health care and life insurance plans. These expenses are shown on Exhibit A-64 (KKG-1), page 1, lines 4 through 6.

Q. Are the expenses for active employee health care (including HSAs and HCFSAs), life insurance, and LTD benefits determined in the same way as expenses for retiree health care and life insurance benefits?

A. No. The expenses for active employees are based upon the actual costs for these benefits that are expected to be incurred. The expenses for retirees are determined using actuarial analysis, which is performed by the Company's actuary, in accordance with ASC 715, formerly known as Financial Accounting Standards ("FAS") 106.

Q. How were the portions of active employee and retiree health care (including HSAs and HCFSAs), life insurance, LTD, and other benefits costs allocated to gas O&M expense determined?

A. The portion of the Company's total program expenses attributable to the gas utility was allocated based upon an annual study by the Accounting Department of the relationship of the number of employees in the gas utility to the total number of employees in both the electric and gas utility. The amount allocated to the gas utility is allocated between O&M expense and capital expense based upon the Accounting Department's formula. For the projected years 2024 thru the 12 months ending October 31, 2026, costs were split using 55% electric and 45% gas, with 61% capital on gas expenses.

<u>Active Health Care (Including HSAs and HCFSAs), Life Insurance, LTD, and Other Benefits</u>

Q. Please describe the development of the active health care (including HSAs and HCFSAs), life insurance, and LTD expense levels that are shown on Exhibit A-64 (KKG-1), page 1, line 4, which begins with $18,359,000.

A. Exhibit A-64 (KKG-1), page 1, line 4, contains gas operations O&M expenses for the Company-funded benefit plans for active employees' health care (including HSAs and HCFSAs), life insurance, and LTD. The primary component of this expense is health care. Life insurance and LTD make up a much smaller portion of the expense. In 2023, the Company incurred an actual combined expense of $18,359,000 for health care, life insurance, and LTD for gas operations. The projected gas operation expense for these benefits for the projected test year is $19,765,000.

Q. What factors did you consider when projecting the test year's expenses for health care, life insurance, and LTD?

A. In projecting the test year's health care expenses, a number of factors were considered. The primary factors included current and projected inflation factors and a review of 2023 and 2024 national health trends/costs survey information provided by Willis Towers Watson ("WTW") actuarial consulting. Additional factors considered were the Company's medical and prescription drug carrier's health cost and claims experience expectations, the continuing rapid rise in availability and price of specialty prescription drugs, the current employee headcount, and the continuing cost increase impacts of national health care reform.

Q. Please explain how these factors were used to determine the Company's expected health care costs.

A. The Company has determined that using the inflation factors in this case will keep cost increases in line with inflation amounts. Exhibit A-64 (KKG-1), page 2, line 4, column (i), compares the projected test-year expense with the 2023 actual expense, adjusted for 2024, 2025, and 2026 inflation, to calculate other adjustments.

To further understand projected health care trends and costs, the Company and WTW reviewed expected health care trends and costs survey information from several large consulting firms. The Company and WTW also reviewed the Company's actual health care claims experience for employees and retirees in its health plans - Blue Cross/Blue Shield of Michigan ("BC/BS") and Express Scripts. This analysis of the Company's health plans revealed that the Company's workforce is older than the average age of the population insured by the BC/BS and Express Scripts plans, and as a result, the

Company's health plans have a higher expected utilization rate that is associated with an older covered population. Of the Company's current workforce, as of December 31, 2023, 49% of employees are over age 45; 34% are over age 50; and 20% are over age 55. The Company understands the older age of its workforce is expected to lead to a higher health care expense (primarily due to utilization of services).

To project future health care expenses, the Company and WTW also considered all the plan changes and programs that the Company has already implemented. These changes include sharing expected health care expense increases with employees through plan design changes like increased deductibles, copayments, and out-of-pocket maximums; increasing employee premium contributions for coverage; adding telehealth benefits to medical plans to lower expense; educating employees regarding the prudent and informed use of health care benefits; promoting use of preventive benefit services; promoting well-being through Live Well 365, which is integrated into all medical plan designs, that encourages and rewards plan participants for taking steps toward healthier lifestyles; securing favorable pricing on prescription drugs obtained through a large employer prescription drug collaborative; negotiating lower administrative fees with health plans and promoting enrollment into the Consumer Directed Health Plan ("CDHP"), a high deductible health plan which currently provides a Company contribution to the participant's HSA.

The Company and WTW also considered the specific changes to the union employees' health care plan benefits as negotiated in its 2020 through 2025 contracts, as well as changes made to the employees' health care benefit plans in 2021 described in detail later in this direct testimony. While there are very tangible savings in future health expenses to the Company and its customers as a result of these changes to employee health care benefit plans, the Company believes a portion of these savings will be offset by increased health expenses incurred under national health care reform requirements (like Patient Centered Outcomes Research Institute fees, employer mandate shared responsibility administrative/reporting requirements, and potential penalties) as well as increased prescription expenses due to the availability of new and expensive specialty prescription drugs in the market. In addition, while the Company has taken numerous steps to control the rising expense of health care, many of these changes are one-time events that lower a plan's expense in that year to establish a new baseline moving forward, but future health care expenses then continue to increase from the new baseline expense.

Q. What are some of the reasons that health care costs are increasing at a level higher than general inflation?

A. There are a number of factors causing a higher rate of health care inflation than is reflected in the general Consumer Price Indexes ("CPIs"). Health care costs are expected to continue rising during the next several years due to an aging population living longer, additional utilization of services, price increases for services, new medical technology, cost shifts from government plans, mandated benefits coverage, rising provider malpractice premiums, new taxes on health claims, and rapidly escalating prescription drug prices including high prices for new, expensive specialty drugs. In addition, national health care reform will increase Company health care costs in the near term because of eligibility expansions (e.g. adult children to age 26), mandated benefits, removal of annual dollar limits, additional taxes, fees, penalties, new compliance/reporting requirements, and more government shifting of costs through Medicare and Medicaid expansion. These factors are all outside the control of Consumers Energy. Even with all the employee and retiree health plan design and premium contribution changes made annually by the Company over a number of years, including the move to Live Well 365 program incentives, health care costs for the Company are still expected to continue increasing annually at a rate two to three times that of general CPI inflation. The assumption that health care costs will only increase at the general rate of inflation has not been the actual experience for many years and is not expected in the foreseeable future.

Q. Are increases in health care costs being experienced both locally and nationally?

A. Yes. While increases in health costs have moderated, both local and national health care costs continue to increase at rates greater than general CPI inflation.

Q. Are the significant increases in health care costs limited to active employees?

A. No. Health care costs are also increasing at a rate higher than the general CPI inflation for retirees for the same reasons cited earlier. In fact, retiree expenses are generally increasing at higher rates because of retirees' older ages and the resulting increases in utilization, particularly in the use of prescription drugs, including higher-priced specialty prescription drugs. The projected increases for active employee health care, like projected increases for retiree health care, are substantial, expected to occur, and largely beyond the control of the Company.

Q. Please describe the development of the expense levels for active employee life insurance and LTD costs included in Exhibit A-64 (KKG-1), page 1, line 4.

A. For 2024, the Company used inflation factors of 3.2%. In 2025, the Company used 2.4%, and for 2026, 2.5% was used. These expense estimates are reasonable as both life insurance and LTD premium costs are based on wage and salary levels and changes to this coverage throughout the year. The 3.2%, 2.4%, and 2.5% annual increases represent the normal, expected merit increases in salaries/wages, increases due to salary adjustments made for job changes and promotions throughout the year, any upward movement in Company-paid life insurance coverage in each annual enrollment period, and increases in premium rates due to plan experience.

Q. What has the Company done to control the increase in active employee and retiree health care, life insurance, and LTD expenses?

A. The Company has aggressively managed these benefit costs for more than a decade. Significant changes have been made to all health care, life insurance, and LTD plans since the introduction of the Benefit by Choice program first implemented in 2002, which offered employees and retirees different levels of health, life, and LTD coverage. A summary of various changes made to manage the cost of the Company's health care plans offered to employees and retirees from 2002 through 2024 follows:

- Reduced the number of dental plan offerings by consolidating to one plan;
- Implemented additional specialty prescription savings programs to reduce member and Company costs;
- Reduced the number of healthcare plan offerings by eliminating two health maintenance organization ("HMO") plans;
- Joined prescription drug collaborative to improve efficiencies on pricing, customer service, and access to affordable prescription drug coverage;
- Streamlined all benefit plans to 80% coverage levels;
- Offered a telemedicine option for those seeking treatment for non-emergent conditions;
- Increased employee/retiree premium contribution levels annually;
- Implemented Preferred Provider Organization ("PPO") plans, providing discounted networks to all participants;
- Reduced the level and number of PPO plan benefit coverage levels from 90%, 80%, and 70% to 85% and 70%;

- Reduced HMO plan benefit coverage levels from 100% to 90%;
- Increased, on several occasions, employee/retiree PPO and HMO plan design cost sharing provisions including medical/dental deductibles, out-of-pocket limits, office copays, urgent care copays, and emergency room copays;
- Switched to Maintenance of Benefits (“MOB”) coordination;
- Required covered spouse working full-time to have own employer coverage primary;
- Negotiated administrative fees and insured plan premium rates annually, and bid in the health plan market to improve pricing;
- Increased employee/retiree prescription drug benefit cost sharing through incentive four-tier plan designs, higher prescription drug copays and coinsurance, and use of an exclusive network for specialty drugs;
- Implemented prescription drug management programs including full-menu, dynamic-based coverage management programs, mandatory use of mail order, safety/efficiency provisions, and regular market bids for pricing through an employer collaborative;
- Implemented health and disease management programs and added case management;
- Implemented a Company-defined dollar contribution plan management approach;
- Eliminated duplicative, higher cost health plan offerings on several occasions;
- Introduced informed consumerism, cost information, and credible health resources;
- Used enhanced technology for more timely determination of plan eligibility and coverage;
- Implemented access-only retiree health care benefits for new hires (no Company subsidy);
- Implemented preventive benefits with no cost sharing, included the mandated changes required under the Affordable Care Act (“ACA”);
- Implemented and promoted enrollment in a CDHP with an HSA;
- Increased premiums and out-of-pocket limits;

- In 2018, implemented new total well-being program called Live Well 365. This program allows employee/preMedicare retirees to be engaged in their total well-being through a variety of well-being activities including, but not limited to, preventive exam, well-being assessment, physical challenges, and a variety of other activities available to increase year-round engagement. For those participants who complete level 1 of the Live Well 365 program, they remain in a higher benefit coverage level or receive an additional Company HSA contribution. Employees/preMedicare retirees that do not participate in Live Well 365 are moved to a higher out-of-pocket cost benefit coverage level or do not receive the second Company HSA contribution;

- Separated employee/retiree medical and dental plans to minimize reporting and compliance costs required by the ACA;

- Changed insured HMO plans to self-insured HMO plans; implemented an ongoing medical/dental/vision plan dependent audit process to ensure only eligible employees, retirees, and their dependents are covered by these plans;

- Secured improved prescription drug pricing and plan consulting services as part of membership in a large prescription drug employer prescription drug purchasing collaborative;

- Made plan design changes to Salaried Active Medical plans to out of pocket limits so Union and Salaried plans match;

- Implemented premium decreases in both the Salaried Active Community Blue Medical and the Aetna Traditional Medical Plan for Retirees;

- Converted Active, Retiree, Dependent Life and AD&D from The Hartford to MetLife;

- Moved to Age Banded rates for Retiree Life (includes both Employer and Retiree contributions); and

- Eliminated eligibility for Salaried Retiree Life – Employer Paid for those who retired on/after 1/1/2024. They may still participate in Retiree Life, but at their own cost.

Q. What changes were made to the 2020 health care plans?

A. In 2020, the Company discontinued offering HMO plans for active employees. This change was due to declining enrollment and higher medical and prescription costs in the HMO plans. Active employees had the option to choose from three other high-quality PPO plans for 2020 coverage. The PPO plans offered an expanded network of providers both in and out-of-network. Active employees who elected the CDHP had the ability for saving options for current and future health care expenses through an HSA. The employee share of health care plans increased.

Q. What changes were made to the 2020 health care plans due to the COVID-19 pandemic?

A. The Company incorporated the following health care changes related to the COVID-19 pandemic. The coverage for COVID-19 Diagnostic Testing and Services required under Section 6001 of the Families First Coronavirus Response Act (the "FFCRA"), as amended by Section 3201 of the Coronavirus Aid, Relief, and Economic Security Act (the "CARES Act") and associated subsequently issued guidance (together, the "Diagnostic Coverage Mandate") required the Company to cover certain diagnostic and preventive services related to COVID-19 without imposing any cost-sharing requirements, requiring prior authorization, or imposing other medical management requirements. Effective March 18, 2020, the Company provided coverage in accordance with the applicable requirements of the Diagnostic Coverage Mandate through the duration of the public health emergency related to COVID-19 as declared by the Secretary of the United States Department of Health and Human Services.

Effective from March 18, 2020 through June 30, 2020, the Company had to provide coverage for treatment related to a diagnosis of COVID-19 at no cost (i.e. without cost sharing) to participants and their covered family members. Effective from March 18, 2020 through June 30, 2020, the Plan provided coverage for telehealth and online visits at no cost (i.e. without cost sharing) to Plan participants and their covered family members.

Q. What changes were made to the 2021 health care plans?

A. In response to the COVID-19 pandemic, the Company continued to offer coverage for COVID-19 diagnostic testing and services without imposing any cost-sharing requirements for employees and covered family members. The Company did not make any significant changes to the health care plans and employee premium contribution for health care. The Company continued to offer quality health care coverage for employees to ensure a healthy workforce to better serve customers.

Q. What changes were made in the 2022 health care plans?

A. In response to the COVID-19 pandemic, the Company continued to offer coverage for COVID-19 diagnostic testing and services without imposing any cost-sharing requirements for employees and covered family members. The Company did not make any significant changes to the health care plans and employee premium contribution for health care. The Company continued to offer quality health care coverage for employees to ensure a healthy workforce to better service customers.

Q. What changes were made to the 2023 health care plans?

A. In 2023, the Company added Domestic Partner Coverage to our Health Care Plans. This is an important benefit to offer employees to ensure our benefits attract and retain a diverse workforce. The additional coverage will result in engaged employees and excellent service for customers. Also, the Company increased health care plan designs (deductible, out-of-pocket limits, and prescription copays) for the traditional PPO plan for both union and salaried coworkers. The Company increased health care premiums for the CDHP and eliminated one of the dental providers to improve overall dental costs. Lastly, the Company continued to utilize a cost-savings plan for certain Specialty Drugs through our prescription provider. Overall, the Company is continuously managing its health care vendors for cost efficiencies, implementing reasonable health care plan design and premium increases, and eliminating choice on the dental plans.

Q. What changes were made to the 2024 health care plans?

A. In 2024, the Company made a plan design change in the Salaried Active Medical plans so the out-of-pocket limits for both Union and Salaried employees are now the same. In addition, changes were made to decrease premiums in the Salaried Active Community Blue Medical for active employees.

<u>Retiree Health Care and Life Insurance</u>

Q. Would you please explain your Exhibit A-64 (KKG-1), page 1, line 5, for retiree health care and life insurance, which begins with ($33,761,000) in 2023?

A. Exhibit A-64 (KKG-1), page 1, line 5, reflects the actual 2023 and projected 12-month period ending October 31, 2026, gas utility retiree health care and life insurance expenses under ASC 715 (formerly known as FAS 106 expense). Each of the annual expense levels shown on line 5 is the total of two separate items which make up the total expense. Each year's expense contains an ASC 715 expense calculation and an actuarial services expense.

Q. How does the Company determine its ASC 715 expense for retiree health care and life insurance?

A. The expense is determined using actuarial analysis that is performed in accordance with ASC 715. Consumers Energy follows GAAP for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodologies and assumptions required to properly calculate and account for retiree health care and life insurance expense which includes evaluation of market conditions at each of the plan's measurement dates. The calculations required by the accounting standards are performed at least annually by the plan's actuary, Aon, using information specific to the Company's OPEB plan. In addition, the Company's auditor rigorously reviews the process to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of retiree health care and life insurance expense (OPEB expense or formerly FAS 106 expense). The expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. Year-end disclosure information is also produced, based on these accounting standards, to provide a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this gas rate case, OPEB were measured in January for the year-end 2023.

Q. What are the components of the annual ASC 715 retiree health care and life insurance expense?

A. There are four components of the annual ASC 715 retiree health care and life insurance expense: (i) service cost; (ii) interest cost; (iii) expected earnings on plan assets; and (iv) amortization of gains and losses, prior service costs or credits, and any transitional amounts. Service cost represents one year's expected benefits earned by active covered employees. Interest cost represents interest on the plan's benefit obligation (its liabilities) due to the passage of time. There is also an assumption made for the expected rate of return on plan assets. This rate of return assumption is intended to be a long-term assumption based upon the best estimate of long-term expected investment earnings of the plan assets. The last component represents amortization of various plan experiences that were not anticipated by the actuarial assumptions.

In order to calculate the plan's total benefit obligation and annual ASC 715 retiree health care and life insurance expense, the actuary uses a number of assumptions including health care inflation trend rates, mortality table, the rate of employee retirements from the Company, the actual retiree health care and life insurance claims of the Company, a discount rate, and the expected contributions to the plan. The methods used to set assumptions are generally consistent, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary. The method used to set the discount rate and expected return on plan assets is the same as the method used for the pension plans, as discussed above.

Q. Are actuarial and administrative expenses included in Exhibit A-64 (KKG-1), page 1, line 5?

A. Yes. An annual expense for the actuarial and administrative services provided for the retiree health care and life insurance plans is included in Exhibit A-64 (KKG-1), page 1, line 5.

Q. What changes were made to the 2020 retiree health care plans?

A. The preMedicare retirees had the same health care plan options as the active union and nonunion employees. The pre-Medicare retirees no longer had the option to select the HMO plans. The pre-Medicare retirees had the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who received a Company subsidized HRA received a 2% increase into their HRA. These retirees select their retiree health care coverage through an individual Medicare marketplace. The private Medicare marketplace specializes in assisting retirees select the best quality healthcare plan options at the most affordable price. The HRA subsidy amount was allotted based on years of service and hire date.

Q. What changes were made to the 2021 retiree health care plans?

A. The pre-Medicare retirees had the same health care plan options as the active union and nonunion employees. The pre-Medicare retirees no longer had the option to select the HMO plans. The pre-Medicare retirees had the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who received a Company subsidized HRA received a 2% increase into their HRA. These retirees selected their retiree health care coverage through an individual Medicare marketplace discussed above. The HRA subsidy amount was allotted based on years of service and hire date.

Q. What changes were made to the 2022 retiree health care plans?

A. The pre-Medicare retirees had the same health care plan options as the active union and nonunion employees. The pre-Medicare retirees had the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who receive a Company subsidized HRA received a 2% increase into their HRA. These retirees select their retiree health care coverage through the individual Medicare marketplace discussed above. The HRA subsidy amount was allotted based on years of service and hire date.

Q. What changes were made to the 2023 retiree health care plans?

A. The pre-Medicare retirees have the same health care plan options as the active union and nonunion employees. The pre-Medicare retirees have the same COVID-19 health care plan changes as the active union and nonunion employees. The Medicare eligible retirees who receive a Company subsidized HRA will receive a 2% increase into their HRA. These retirees select their retiree health care coverage through an individual Medicare marketplace discussed above. The HRA subsidy amount is allotted based on years of service and hire date. Effective January 1, 2023, the Company is only offering a single dental plan, which allows for lower premiums and access to a wider provider network.

Q. What changes were made to the 2024 retiree health care plans?

A. In 2024, changes were made to decrease premiums in the Aetna Traditional Medical Plan for Retirees.

Q. Do the calculations for the retiree health care and life insurance expense follow the prescribed methodology of ASC 715?

A. Yes. The amounts are projected based on ASC 715 using information specific to the Company's retiree health care and life insurance plans. For this gas rate case, the OPEB Plan was measured in January 2024 for year-end.

Q. Has the Company applied the ASU No. 2017-07 Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this case for OPEB?

A. Yes, the Company adopted the ASU No. 2017-07 as of January 1, 2017, and has applied the Standard in this case for both Pension and OPEB.

Q. Please describe the development of the retiree health care and life insurance expense levels that are shown on Exhibit A-64 (KKG-1), line 5, which begins with ($33,761,000) in 2023.

A. The O&M retiree health care and life insurance expense level shown on line 5 for the gas utility is based upon Aon's actuarial determination of the plan's expense for that period in accordance with ASC 715 plus the cost for actuarial and administrative services related to these plans. Due to the retiree medical plan changes described earlier, the actual 2023 O&M retiree health care and life insurance expense for the gas utility was ($33,761,000). The projected gas O&M retiree health care and life insurance expense is ($42,702,000) for the test year. Exhibit A-64 (KKG-1), page 2, line 5, column (i), compares the Aon actual calculation of expense with the 2023 actual expense, as adjusted for 2024, 2025, and 2026 inflation, to calculate other adjustments..

Q. Why is the retiree health care and life insurance expense higher in 2023 and decreasing in the test year?

A. Year 2023 had higher-than-expected asset returns, which caused the lower projected expense in the test year.

Q. Would you please explain your Exhibit A-64 (KKG-1), page 1, line 6, for Other Benefits, which begins with $2,493,000 in 2023?

A. Exhibit A-64 (KKG-1), line 6, reflects the actual 2023 and projected 12-month period ending October 31, 2026 expenses for the gas utility benefits labor, the absence management program, the educational assistance program, the employee assistance program, and the Leaving It Better Award program. The adjustment in Exhibit A-64 (KKG-1), page 2, line 6, column (i), compares the projected test-year expense with the 2023 actual expense, adjusted for 2024, 2025, and 2026 inflation, and the addition of the Leaving It Better Award program to calculate other adjustments.

Q. Please explain why the absence management program is important to attract and retain employees.

A. Paid sick leave is needed to attract and retain employees. In 2014, the Company retained Reed Group, now known as Alight, as an external consultant to manage the Company's absence process. Since the relationship's inception, Alight has been able to improve the absence rate and provide a higher level of standardization, controls, and overall best practices to mitigate risk. Additionally, this streamlined approach ensures a procedure for all employees who need a leave of absence for any purpose.

Q. Please explain why the educational assistance program is important to attract and retain employees.

A. Educational assistance programs are widely available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. The Company offers partial tuition reimbursement to all employees. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company, particularly considering the large number of retirement-eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Safe, reliable, and affordable gas service begins and ends with the Company's people. Investing in and retaining trained, experienced, and motivated employees' benefits customers as much as, or more than, any investment in infrastructure. Educational assistance is just such an investment. It provides the opportunity for employees to continue their education, which further improves their skills to serve the customers of the Company.

Q. Please explain why the employee assistance program is important to attract and retain employees.

A. The Company offers employees, retirees, and dependents access to an assistance program which provides support to help resolve or manage problems that interfere with the ability to perform at work or in life. The employee assistance program provides a variety of on-line tools, face-to-face interactions, and telephone support. The program is designed to aid with any type of need, distraction, concern, or crisis. The employee assistance program provides legal support, financial information, work-life solutions, online services, and confidential counseling. The goal of the program is to improve the overall total well-being for all the Company's employees and retirees.

Q. What is the Leaving It Better Award employee recognition program?

A. The Leaving It Better Award is used to recognize and reward regular salaried, exempt, and non-exempt employees who impact the Company's success by exhibiting the Company's vision and culture in a way that furthers the Company's goals, operational excellence, customer satisfaction, and corporate reputation. Leaders nominate employees and employees can receive a lump sum of up to $4,000.

Q. Please explain the benefits of the Leaving It Better Award?

A. This additional employee recognition is a way to show employees that they are valued for their work, increases the level of productivity at work, and reduces employee turnover, which supports improved service to customers. While the Company already provides merit pay increases for employee achievement of goals and objectives and accomplishment of tasks, duties, and responsibilities as set out in an employee's annual performance evaluations, the employee recognition in the form of a Leaving It Better Award provides additional recognition for going above and beyond the everyday expectations to serve the Company and its customers.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

DIRECT TESTIMONY

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Quentin A. Guinn and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Principal Metrics & Analytics Specialist.

Q. What are your responsibilities as Principal Metrics & Analytics Specialist for Consumers Energy?

A. As Principal Metrics & Analytics Specialist, I am responsible for providing support and direction for Facilities, Real Estate, and Administrative Operations strategy development, compliance, resource planning, and regulatory proceedings. The Facilities execution plan ranges from activities related to gas operations to those involving corporate operational areas of Consumers Energy. Facilities' asset portfolio consists of over 55 buildings and includes the corporate office, storerooms, distribution centers, maintenance garages, service centers, welding and fusion workshops, learning and development buildings, coal generation, wind generation, gas compression, and hydroelectric sites. My responsibilities include regulatory compliance, rate case execution, corporate policy administration, organizational vision, and resource planning for field execution.

Q. What is your formal educational experience?

A. I hold a bachelor's degree in economics from Yale University, located in New Haven, Connecticut, and a Juris Doctorate degree from Washington University, located in St. Louis, Missouri.

Q. Would you please describe your previous work experience?

A. In 1999, I started my career at Consumers Energy as a Contracts Analyst. In 2000, I began a series of changing roles, with increasing responsibility, from Contracts Supervisor to Director of Contract Services. In each successive role, I led teams of Contract Analysts and Contract Administrators who were responsible for a broad range of construction, maintenance, consulting, information technology, and engineering contracts. The responsibilities of these teams included sourcing and evaluating contractors and consultants, developing scopes of work, competitively bidding work, negotiating agreements, and administering contracts. In 2013, I began work in a series of successive roles focused on data, analytics, performance, and work management culminating in my current role as Principal Metrics & Analytics Specialist.

Q. What is the purpose and scope of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's costs related to the Gas business portion of Facility Operations ("Facilities"). I will:

- Describe the Gas Operations Support function;
- Describe the methodology employed by Facilities for evaluating the health of its various facilities;
- Support the reasonableness and prudence of the capital expenditures for Asset Preservation for the historical year ended December 31, 2023, the bridge period beginning January 1, 2024, and ending October 31, 2025, and the projected test year ending October 31, 2026; and
- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") expenses for Facilities, Real Estate, and Administrative Operations for the historical year ended December 31, 2023, the bridge period beginning January 1, 2024, and ending October 31, 2025, and the projected test year ending October 31, 2026.

Q. Have you previously testified in a Michigan Public Service Commission ("MPSC" or the "Commission") proceeding?

A. Yes. I have provided testimony on behalf of Consumers Energy Company in Case Nos. U-21148, U-21224, U-21308, U-21389, U-21490, and U-21585.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (QAG-1)	Schedule B-5.6	Summary of Actual & Projected Capital Expenditures;
Exhibit A-68 (QAG-2)		Summary of Actual and Projected O&M Expenses;
Exhibit A-69 (QAG-3)		Detailed List of Projected Gas Capital Expenditures;
Exhibit A-70 (QAG-4)		Service Center Projects – Plan Summaries.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. Please describe the exhibits you are sponsoring.

A. Exhibit A-12 (QAG-1), Schedule B-5.6, details the actual and projected capital expenditures related to Gas Operations Support. Exhibit A-68 (QAG-2) details the O&M costs related to Gas Operations Support. Exhibit A-69 (QAG-3) identifies Gas Operations Support Programs and the projected capital expenditures related to those projects and programs. Exhibit A-70 (QAG-4) details the alternatives considered and customer benefits of each of the three service center projects outlined in this case.

Q. Please explain the Gas Operations Support function.

A. The Gas Operations Support function consists of the following support organizations: Fleet Services, Facilities, Real Estate, and Administrative Operations. Gas Operations Support acquires, constructs, and maintains fixed assets required to operate the functional areas of the business that serve the Company's customers.

Q. Are you addressing all support organizations related to Gas Operations Support in your direct testimony and exhibits?

A. No. Fleet Services will be addressed in the testimony of Company witness Corey E. Ballinger.

Q. What is the function of the Facilities organization?

A. Within Gas Operations Support, Facilities manages, maintains, and operates 55 buildings comprising 3.2 million square feet of building space across the state of Michigan that allow the Company to serve customers across the state in an efficient and effective manner.

Q. How have Company facilities changed over time?

A. The Company experienced major growth in the area of Facilities during the 1950s and 1960s. Nearly half of its buildings were built or acquired during this period and remain in operation today. As a result, many of these buildings are now over 50 years old. The Company made no significant investment in its facilities and initiated no major renovations or construction of new buildings between 1970 and 2000. In 2003, the Company constructed its One Energy Plaza headquarters building in Jackson. This construction marked the adoption of the open office concept (i.e. fewer hard wall offices) at the Company which, among other reasons, was adopted to foster a more collaborative work environment. Between 2000 and 2016, the Company also closed many facilities including 22 service centers across Michigan to adapt to shifting population trends in the state and optimize service to customers.

Q. What structural concerns or problems do these aging structures and facilities create for the Company?

A. Multiple major systems throughout these facilities, such as boilers, chillers, cranes, elevators, emergency generators, heating, ventilation, and air conditioning ("HVAC") systems, lighting, power distribution, paving, roofing, Uninterruptible Power Systems, and vehicle hoists are beyond their useful lives. Further, building materials in the facilities contain hazards such as asbestos and lead paint. Repairs on such aging infrastructure are not always cost effective and can lead to lengthy projects and significant renovation or replacement of entire structures. It is increasingly difficult to identify and obtain adequate parts and to further locate the necessary expertise to work on this aging equipment. In addition, these facilities were not designed to meet modern standards of energy efficiency.

Q. What concerns or problems do these aging structures and facilities create for the Company's customers?

A. The population and infrastructure of the State of Michigan look much different than they did in the 1950s and 1960s. In 1950, the population of Michigan was 6,407,000 with growth focused in urban areas. The state's current population is now over 10 million, with much of the growth since the 1960s having occurred in suburban areas. The Company regularly assesses the optimal location of its facilities needed to effectively serve customers and minimize response times. The Lansing Service Center Project, discussed in detail later in my testimony, originated from this assessment process.

Q. What process does Consumers Energy utilize to evaluate whether to make capital investments in facilities?

A. The Company has been using a formal assessment process for several years that evaluates whether to invest in a facility by studying each facility's overall health. The Company plans to continue using this process and is enhancing it by incorporating the operational priorities of the Facilities organization's internal business partners. Given the evolving nature of the workforce (i.e., with hybrid work) the Company is working on strategies to ensure its facilities are right sized for the needs of the work.

Q. What is the formal assessment process related to facility health?

A. A formal assessment process was established in 2016 to determine the need for capital investments in facilities. The assessment process is re-evaluated every two years resulting in minor updates to the methodology to reduce subjectivity in scoring. The most recent assessment was completed in 2022. The Facilities Department consists of qualified, trained, and certified experts in architecture, HVAC, plumbing, and electrical that conduct the assessment. In that process, an evaluation is made, on a multi-category scale, of certain conditions and characteristics of the structure and functions of the facility being assessed. For each facility, each condition and characteristic is scored (with a score of 1 to 5 per category), and then the facility is ranked on a multi-category scale (with an 80-point maximum score).

Q. What categories are included in the evaluation process of the Company's facilities?

A. Categories that are evaluated include: (i) safety (such as asbestos or other hazardous materials, traffic flow, and compatibility with surrounding areas); (ii) quality (such as workplace efficiency, employee comfort, and employee attraction and retention); (iii) cost (such as facility operating costs, space optimization, and energy efficiency); (iv) delivery (such as response times, driving distance within service territory, and sustainability of operations); and (v) morale (such as employee pride, wellness, and retention).

Q. How is the quality of each category identified above established?

A. The facility evaluated will fall within one of three quality designation categories depending on the score received. A score above 64 is designated as "Good"; a score of 48 to 64 is designated as "Serviceable," meaning that investment and/or replacement is needed; and a score under 48 is designated as "Poor," meaning that there are multiple systems failing at the facility. Facilities designated as "Poor" are typically candidates for replacement.

Q. What is the next step in the facility assessment?

A. Once the facility is initially evaluated and receives a quality designation, operational departments of the business then review and validate the raw scored ranking and adjust the ranking to reflect forecasted needs of the business. Facilities finalizes the score, and any facility that scores below a minimum acceptable level, 48 out of 80 points, may be identified for renovation or replacement.

Q. How does the Facilities organization consider the business needs of its internal business partners when selecting locations for Facilities work?

A. The Facilities organization considers business partner needs by meeting on a regular basis with business partners to review their business plans and the resulting impacts on the facilities necessary to support these plans. The process begins with a 10 Year Long Term Facilities Plan. This plan is maintained by the Facilities organization and contains fundamental information about each facility such as the year the building was constructed, estimated years of useful life remaining in the building, and dates of major milestones in the life of the building (e.g. significant renovations and building additions). Facilities organization engineers and other technical experts across the Company (e.g. Company environmental analysts) generate the health assessments and develop capital investment priorities based on the health assessments (e.g. replacement of specific assets at specific buildings, preventive maintenance of specific building systems, work on a building envelope). These capital investment priorities are then reviewed by business partners for alignment with their business plans and can become planned projects based on this collaboration between the Facilities organization and business partners. While considerable engineering rigor is applied to developing the facility health assessments, business partner priorities do affect the ultimate list of projects. The Kalamazoo Service Center Project included in this rate case, for instance, was elevated in priority to address hazardous material issues and negative employee engagement identified by business partners at the Kalamazoo Service Center.

Q. Does this process ensure priority is given to Facilities projects critical to ensuring the Company can serve its customers?

A. Yes. The facility health assessments and aforementioned planning process produces a prioritized list of facilities for renovation or replacement that is aligned with both the need to preserve and maintain facilities assets and support business plans in providing optimal customer service. Buildings that are in poor condition or are otherwise suboptimal negatively impact the Company's ability to serve customers.

Q. Are there situations in which prioritization of projects might change?

A. Yes. For example, several years ago the Company reprioritized development of a service center in Tawas to provide timely support to customers in the greater Tawas region and to reduce the workload impact on local first responders during response to emergency utility events. In another example, the Company revised its plans for the Kalamazoo Service Center Project included in this case. In this instance, after examining the impacts of the COVID pandemic on the workforce and changes the pandemic brought in how work is performed, the Company revised its original plan to replace the Kalamazoo Service Center and instead decided to renovate portions of it as many of the building modifications originally proposed became more costly due to supply issues and were also deemed no longer necessary to support the post-COVID workforce.

Q. Is the Company taking steps to ensure its facilities are right-sized given changes in the working environment?

A. Yes. The Company is monitoring the use of its facilities in a post-COVID work environment. As the pandemic has subsided, multiple internal organizations have established expectations for in-person work at Company facilities. As a result, Company facilities are continuously evaluated for alignment with current and anticipated work trends. In cases where underutilized workspace has been identified, the Company has divested or examined divesting such space. For example, in 2020, the Company terminated lease agreements for over 30,000 square feet of previously leased office space at the Commonwealth Commerce Center in Jackson. The Company will continue to evaluate space utilization with the goal of eliminating underutilized space and aligning business needs with space requirements.

Capital Spending Overview

Q. What programs are included in the projected capital expenditures for Facilities?

A. As demonstrated in Exhibit A-12 (QAG-1), Schedule B-5.6, Facilities capital spending is divided into two programs: (i) Asset Preservation; and (ii) Other Equipment. Capital spending is broken down into multiple standard cost categories, including contractor, labor, materials, business expenses, and other (loadings, chargebacks). Most Facilities capital spending, as reflected in Exhibit A-12 (QAG-1), Schedule B-5.6, is for Asset Preservation, which is broken down into four portfolio categories: emergent repairs, asset replacement, new construction, and renovations.

Other Equipment

Q. What is included in the Other Equipment program?

A. Other Equipment includes capital investments for wellness equipment; computer equipment; print equipment; Real Estate organization tools and equipment; Supply Chain organization tools and equipment; and Facilities organization tools. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, the Company is projecting to spend $1,148,000 on Other Equipment in the 22-month bridge period and $652,000 on Other Equipment in the projected test year.

Q. Can you elaborate on what the various categories of Other Equipment spending represent?

A. Wellness Equipment consists primarily of equipment used by Operations personnel and others in the Company's fitness centers. Computer Equipment includes computers acquired for use by Operations Support personnel outside of routine lifecycle replacements. These include acquisitions of computer equipment obtained for a specialty use (e.g. a plotter) or replacement of computer equipment that fails prematurely for various reasons. Print Equipment consists of large copying and printing equipment for the Company's Administrative Operations and Mail Room. Real Estate Tools and Equipment consists primarily of survey equipment. Supply Chain Tools and Equipment consists of tools and equipment acquired for material storerooms such as shelving.

Q. How did the Company determine this level of investment for Other Equipment?

A. Levels of investment are set to meet identified needs of the business. The Facilities organization considers business partner needs by meeting on a regular basis with business partners to review their business plans.

Emergent Repairs

Q. What capital expenditures are included in the Emergent Repairs portfolio category?

A. Emergent Repairs includes unplanned corrective maintenance and break fix repair of assets. As shown in Exhibit A-69 (QAG-3), the Company is projecting to spend $1,463,000 in the 22-month bridge period and $1,939,000 in the projected test year on emergent repairs. The Company maintains data on the age, condition, and maintenance history of its major building system assets. This data, in conjunction with historical spend, is used to forecast projected spend on unplanned corrective maintenance and break fix repair of assets.

Asset Replacement

Q. What capital expenditures are included in the Asset Replacement portfolio category?

A. The Asset Replacement portfolio category includes capital replacement of paved surfaces such as parking lots and driveways; roofing; mechanical and electrical equipment in buildings; and furniture. As shown in Exhibit A-69 (QAG-3), the Company is projecting to spend $17,021,000 on Asset Replacements in the 22-month bridge period and $7,838,000 on Asset Replacements in the projected test year.

Q. How are Asset Replacement projects targeted?

A. Similar to the aforementioned facility health assessments, asset condition assessments are performed by Facilities engineers on a regular basis. For example, for roofing assets, a portion of roof sections is inspected annually such that all roofs are inspected once every three years. The condition of each assessed asset is ranked following standard industry-recognized methodologies. Those assets assessed to be below acceptable condition are targeted for renovation or replacement.

Q. How does the Company identify locations for paving projects?

A. The condition of paving assets is evaluated following standard industry practices on a rolling five-year basis with a condition assessment performed annually for 20% of Company sites. Paving assets are prioritized for replacement based on the lowest assessed condition index score. Paving projects may include other related enhancements to paved surfaces such as new drainage or new lighting.

Q. How did the Company determine the amount of needed investment in paving projects for the bridge period and the test year?

A. The total amount of needed investment in paving projects is established using the five-year historical average spend. The condition assessments are then used to determine how that spend is allocated. Specific paving sections are identified for replacement and cost estimates are prepared utilizing historical data from similar paving asset replacement projects performed during the last five years.

Q. How does the Company identify locations for roofing projects?

A. The condition of roofing assets is evaluated on a rolling three-year basis with a visual inspection and detailed infrared inspection performed annually for 33% of Company sites. Roofing assets are prioritized for replacement based on the lowest assessed condition index score.

Q. How did the Company determine the amount of needed investment in roofing projects for the bridge period and the test year?

A. The total amount of needed investment in roofing projects is established using the five-year historical average spend. The roof condition assessments are then used to determine how that spend is allocated.

Q. How does the Company identify locations for mechanical and electrical projects?

A. The condition of mechanical and electrical assets is evaluated by Facilities engineers for all Company sites. Based on the results of these evaluations, targeted maintenance work is performed on mechanical and electrical assets. Where the condition of mechanical and electrical assets is determined to be below an acceptable threshold for targeted repair or maintenance, the mechanical and electrical assets are prioritized for replacement based on the results of these evaluations. The condition of these assets is determined to be below an acceptable threshold for targeted maintenance once the cost of maintenance exceeds the cost of replacement and/or the risk of obsolescence of replacement parts becomes too great.

Q. How did the Company determine the amount of needed investment in mechanical and electrical projects for the bridge period and the test year?

A. The total amount of needed investment in mechanical and electrical projects is established using the five-year historical average spend. Cost estimates are then prepared utilizing historical cost data for each of the mechanical and electrical assets prioritized for replacement. Cost estimates are prepared utilizing historical data from similar mechanical and electrical projects performed during the last five years. Whether the facility in which the mechanical and electrical project is being performed serves only Company gas customers, only Company electric customers, or serves combination electric and gas customers impacts how mechanical and electrical project costs are allocated. In this case, the decrease from $5,552,000 in the 12-month bridge period ending December 31, 2024 to $2,187,000 in the projected test year is largely attributable to the fact that the mechanical and electrical projects being performed during the 12-month period ending October 31, 2026 are being performed primarily in Company facilities that serve only electric customers. Mechanical and electrical projects performed during the historical year were performed primarily in Company facilities that serve only gas customers and facilities that serve combination electric and gas customers.

Q. How does the Company identify locations for elevator projects?

A. The condition of elevator assets for all Company sites are evaluated by outside consultants and subject matter experts. Elevator assets are prioritized for replacement based on the results of these evaluations utilizing a condition assessment score of 1 to 5. Elevators with an assessment score of 3 or below are targeted for modernization or replacement.

Q. How did the Company determine the amount of needed investment in elevator projects for the bridge period and the test year?

A. The total amount of needed investment in elevator projects is established using the five-year historical average spend. Cost estimates are then prepared utilizing historical cost data for each of the elevator assets prioritized for modernization. Cost estimates utilize historical data from similar elevator asset projects performed during the last five years. The cost per individual elevator modernization or replacement varies from year to year depending on the number of floors served by the elevator, weight rating of the elevator, and elevator drive type. Whether the facility in which elevator modernization is being performed serves only Company gas customers, only Company electric customers, or serves combination electric and gas customers also impacts how elevator asset project costs are allocated. In this case, the increase from $55,000 in the 12-month period ending December 31, 2024 to $445,000 in the projected test year is largely attributable to the fact that the elevator asset projects being performed during the 12-month period ending October 31, 2026 are being performed primarily in Company facilities that serve only gas customers. Elevator asset projects performed during the historical year were performed primarily in Company facilities that serve only electric customers and facilities that serve combination electric and gas customers.

Q. How does the Company identify where furniture replacements are needed?

A. Furniture replacement is determined based on business need. Subject matter experts evaluate business unit requirements and existing furniture. Where the existing furniture does not meet business unit requirements the furniture is identified for replacement.

Q. How did the Company determine the amount of needed investment in furniture for the bridge period and the test year?

A. Cost estimates are prepared utilizing historical cost data for each of the furniture assets prioritized for replacement. Furniture project cost estimates utilize historical data from similar furniture asset projects performed during the last five years. Furniture materials are redeployed to compatible users when feasible.

New Construction

Q. What capital expenditures are included in the New Construction portfolio category?

A. The New Construction portfolio category includes major projects to build new structures, either on existing Company property or on new properties the Company acquires. As shown in Exhibit A-69 (QAG-3), the Company is projecting to spend $21,170,000 on New Construction in the 22-month bridge period and $7,199,000 on New Construction in the test year.

Q. Has the Company identified projects in the New Construction portfolio category?

A. Yes. The Company's New Construction projects are listed in Exhibit A-69 (QAG-3) and are as follows:

- Lansing Service Center
- Hastings Service Center
- Gas City Training
- Gas Construction Project

Q. Does the Company consider environmental impacts when planning for new construction?

A. Yes. New buildings incorporate the United States Green Building Council ("USGBC") standards (see usgbc.org), and the Leadership in Energy and Environmental Design ("LEED") standards (see usgbc.org/leed), with specific emphasis on reduced energy consumption, sustainability, and reduced operating cost.

Q. Do these environmental building standards benefit the Company's customers?

A. Yes. When compared to conventional construction, buildings designed to LEED standards reduce lifetime energy consumption by 30% or more, resulting in reduced operational costs which allow customers to pay less for utility costs. In addition, new buildings require less maintenance and are easier to maintain than an aged structure, resulting in an estimated 5% cost reduction. Consumers Energy's recently constructed Coldwater Service Center was designed and built to these standards.

Q. Describe the Lansing Service Center Project. What is its overall goal?

A. In this project, the Company has purchased land in a new location and will construct a new facility on that property. This facility will allow the Company to retire its existing facility (which will be demolished and retained to address and abate environmental concerns resulting from the operation of a former Manufactured Gas Plant ("MGP") on the site). This new facility will house many employees currently working out of the existing service center. The Company anticipates a portion of these employees will have a hybrid work arrangement in which the employees perform some work tasks at the Lansing Service Center and some work tasks elsewhere including their homes. Employees with a hybrid work arrangement will require collaborative space and use office desk space with open seating in the facility when they are on-site to work with other personnel.

Q. What alternatives to the construction of a new Lansing Service Center did the Company consider?

A. The Company considered the following three alternatives: (1) do nothing; (2) renovate the existing Lansing Service Center; and (3) construct a new facility at a new location, with multiple locations considered. The option to construct a new facility at a new location was determined optimal.

Q. Why has the Company chosen to build a new Lansing Service Center?

A. As demonstrated in Exhibit A-70 (QAG-4), a Facilities assessment of the existing Lansing Service Center produced a score of 39, placing the existing Lansing Service Center in the quality designation of "Poor." This information led the Company to rule out a "do nothing" option, and problems with the existing facility's location led the Company to rule out building a new facility on the same site. The existing facility is built on the site of a former MGP, with impacted soil materials underlying the building and other structures. The existing facility is also located within the Grand River flood plain with the building floor elevation three feet below the river's flood stage. Additionally, the existing facility is in a residential neighborhood and is served by a local road network with schools nearby, resulting in large truck traffic being routed through the residential area, which may be a safety hazard for residents (especially children). Crime in the existing area is also a problem as the site has experienced multiple law enforcement incidents involving the pursuit of armed suspects through the property, including areas within the secured perimeter. These incidents have resulted in the Company's inability to move vehicles out of the service center (while police officers were pursuing suspects), and a general level of unease regarding the safety and security of employees.

Q. Please elaborate on the reasons the Company decided to build a new Lansing Service Center.

A. As reflected in the scores set forth in Exhibit A-70 (QAG-4), there are several reasons the Company has chosen to relocate the existing Lansing Service Center. These reasons range from the age of the building to customer accessibility. First, the existing service center building was built in 1958. Over time, systems of the building, including major mechanical and electrical systems, even with regular maintenance and replacement, are beyond their useful lives. Currently, these systems require substantial renovations/replacement. Additionally, the existing service center is located in a residentially zoned neighborhood and due to the location, does not allow Gas Operations to meet customer needs in a timely fashion. Further, the roads (because of the residential zoning) are inadequate for the size of equipment utilized in and out of the service center and there are often children in the vicinity, which creates significant safety concerns. The current site is also located within the floodplain of the Grand River with the finish floor elevation located three feet below the major flooding elevation projected by the Federal Emergency Management Agency. All these considerations negatively impact the Company's ability to dispatch both personnel and equipment to serve customers. Other considerations supporting the decision to construct a new facility, rather than renovate the existing facility, include operating cost reductions, security, and environmental abatement. Because of these factors, the Company has decided to build a new Lansing Service Center at a new location, with the evaluation of potential locations summarized in Exhibit A-70 (QAG-4).

Q. Can you elaborate further on the security and environmental abatement issues at the Lansing Service Center?

A. Yes. The site has experienced multiple law enforcement incidents, some involving the pursuit of armed suspects across and through the property, including areas within the secured perimeter. These incidents have resulted in lock-down safety protocol implementation for employees and a resulting general level of unease regarding the safety and security of employees, customers, and others, while on the property and when accessing or leaving the property. Environmental issues arise from the use of the current

Lansing Service Center site as the location of a former MGP regulated under Public Act 451 of 1994, Part 201. This site has historical environmental contamination issues resulting from operation of the MGP, including significant underground impacted soil materials (i.e., coal tar residual). Additionally, the facility contains asbestos insulation for pipe and duct work, asbestos flooring, and has significant areas of lead paint in poor and peeling condition. Given these environmental issues, upgrades to the facility (e.g. carpet replacement and open space enhancement) cannot be cost effectively completed.

Q. Has the Company engaged in an environmental study for the area contemplated for the new Lansing Service Center?

A. Yes. The proposed new site for the Lansing Service Center includes previous agricultural use; thus, no environmental impacts are anticipated from this previous use. A Phase 1 Environmental investigation has been completed. The proposed site contains wetland areas and current development plans envision leaving these wetland areas undisturbed. A wetland assessment has also been completed.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Lansing Service Center?

A. The proposed new Lansing Service Center facility is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

Q. The Lansing Service Center Project includes the relocation of that facility to a different part of the Lansing metropolitan area. Can you explain what is considered generally when considering relocation of a facility?

A. Yes. As noted earlier, Company facilities are assessed and scored based on multiple criteria (i.e., safety, quality, cost, delivery, and morale) to provide a holistic score that informs the Company of the possible need to make investments to make improvements. Facilities with scores falling below the acceptable range are targeted for renovation or replacement. Part of the overall analysis, which is relevant to the Lansing Service Center, is the geographic location of targeted facilities. Geographic locations are analyzed against customer workload distribution within the service territory to determine optimal location for the facility. Facilities that are determined to be mis-located within the customer service territory are evaluated for relocation to a newly constructed site with the goal of improved customer response. Facilities determined to already be optimally located within the customer service territory are evaluated for renovation or reconstruction on the existing site.

Q. How did the Company determine the new location for the Lansing Service Center?

A. An analysis of customer distribution across the service territory where the Lansing Service Center is located, and potential service center locations within that service territory, determined the optimal area to minimize response times. This analysis is reflected in Exhibit A-70 (QAG-4). Reducing customer response times lowers fuel costs by minimizing the distance Company employees must travel to job sites. Determining the optimal area to minimize response times also maximizes employee efficiency by reducing labor hours required to reach and service customers. The current location of the Lansing Service Center is offset to the north and east of the optimal location, in a residentially zoned neighborhood, and the current location does not provide readily available highway access. The current location of the Lansing Service Center within the service territory results in increased customer response times, higher fuel costs, and reduced employee efficiency due to increased travel times as explained above. The location for the new Lansing Service

Center will not only be in a more appropriately zoned area but will also provide improved customer response times. See Exhibit A-70 (QAG-4).

Q. Has land been acquired for the Lansing Service Center? If so, please identify the location of the land.

A. Yes. Land was acquired for the Lansing Service Center in December 2020, located in Windsor Charter Township, at the southeast corner of the intersection of Canal Road and Billwood Highway, Dimondale, Michigan 48821. The Conceptual Site Plan for the New Lansing Service Center is included in Exhibit A-70 (QAG-4).

Q. What type of operations departments will work at the new Lansing Service Center as compared to the existing Lansing Service Center?

A. The existing Lansing Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; Gas Engineering & Supply; Generation Operations & Compression; Information Technology ("IT"); Electric Operations; Operations Performance; Shared Services; and People & Culture. The Company anticipates personnel from some (not all) of these operating groups to be housed in the new Lansing Service Center.

Q. Approximately how many employees will work at the new Lansing Service Center as compared to the existing Lansing Service Center?

A. Over 450 employees are assigned to the existing Lansing Service Center. The Company anticipates the new Lansing Service Center will house some (not all) of these employees with some adaptation in their use of the workspace including some employees adopting a hybrid work arrangement, requiring only collaborative space and using office desk space with open seating in the facility when they are on-site to work with other personnel.

Q. How much did the Company invest in the Lansing Service Center Project in the 2023 historical year in this case?

A. In the 2023 historical year in this case, the Company invested $1,501,000 (gas allocation) in this project. See Exhibit A-69 (QAG-3). Expenditures in the 2023 historical year were for design engineering a municipal water main extension to the project site, pipe materials for the water main extension, and completion of an alternatives analysis for the project.

Q. How much does the Company project to invest in the Lansing Service Center Project in the bridge period and test year in this case?

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $14,937,000 (gas allocation) in the Lansing Service Center in the 22-month bridge period and $7,199,000 (gas allocation) in the test year. As shown in Exhibit A-69 (QAG-3), page 3, the overall project is anticipated to cost $56.3 million.

Lansing Service Center Plan Costs

Q. How have these projected costs been derived?

A. A construction management firm has been engaged to develop and prepare a detailed design program and construction schedule for the Lansing Service Center project. This firm has evaluated the design program and construction schedule to develop project cost estimates.

Q. What is the status of the Lansing Service Center Project at the time of this filing?

A. Land acquisition and rezoning of the parcel in Dimondale has been completed. Design engineering and bidding have been completed and a contract awarded for a municipal water main extension to the project site. Materials have been ordered for the water main extension and installed. A design-build contract for construction management services has been competitively bid and awarded. Architectural detailed design of the building is near completion. Materials are being ordered for construction of the building with construction scheduled to begin in 2025.

Q. Please describe the Hastings Service Center Project.

A. The Company is planning to construct a new Hastings Service Center at the existing service center location to include an adjacent property that the Company is negotiating to purchase from the adjacent landowner. This new facility will house most employees currently working at the existing service center. A portion of the employees currently working at the existing service center will have a hybrid work arrangement and will require only collaborative space and use office desk space with open seating in the facility when they are on-site to work with other personnel.

Q. What alternatives to the construction of a new Hastings Service Center did the Company consider?

A. The Company considered four alternatives: (1) do nothing; (2) renovate the existing Hastings Service Center; (3) demolish the existing building and construct a new building on site; and (4) construct a new facility at a new site. The options to either demolish the existing building and construct a new building on site or demolish the existing building and construct a new building at a larger site were identified as optimal depending on availability of suitable land.

Q. Why has the Company chosen to construct a new Hastings Service Center facility?

A. As demonstrated in Exhibit A-70 (QAG-4), a Facilities assessment of the existing Hastings Service Center produced a score of 41. As discussed above, because this score falls below a score of 48, it was targeted for replacement, and the “do nothing” option was ruled out.

For the same reason that the Lansing Service Center was targeted for replacement, including aging infrastructure, which is beyond useful life, the Hastings Service Center was determined to need replacement. The current site is fully developed and is no longer sufficient to support ongoing utility operations as the site lacks adequate space for both safe vehicle maneuvering and utility construction material storage. In addition, the existing building envelope does not comply with current energy code requirements. The Facilities organization, therefore, ruled out the renovation option for the Hastings Service Center. The existing Hastings Service Center site is located within an industrialized area with access to major roads and highways. The Company determined that the facility is currently in an optimal location to service customers (see Exhibit A-70 (QAG-4)). Therefore, with the acquisition of appropriate adjacent parcels, the Hastings Service Center has been targeted for replacement on the existing site in lieu of relocation. Other considerations supporting the decision to replace the existing site include operating cost reductions and environmental abatement.

Q. Can you further elaborate on how these alternatives were compared?

A. The Company originally sought to construct a new facility on the existing property. Construction of the new Hastings Service Center on the existing property was predicated on reaching an agreement with the adjacent landowner to transfer a portion of their property to Consumers Energy. This would increase the available site area for development and provide enough space for the new facility. Agreement for a property transfer with an adjacent landowner was not reached, and the properties on the west and east are fully developed. The Company then entered negotiations with the Barry County Road Commission (owner of the adjacent parcel to the south). The Barry County Road

Commission approved the Company's conceptual plan for development of this parcel. The Company now anticipates completing acquisition of the parcel in the fourth quarter of 2024 which will allow for expansion of the existing Hastings site and construction of the new facility.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the new Hastings Service Center?

A. The proposed new Hastings Service Center facility is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

Q. Will this building be larger or smaller than the existing Hastings Service Center?

A. The conceptual site plan for the new service center is shown in Exhibit A-70 (QAG-4). The original projected building area based on conceptual data assembled is larger than the existing Hastings Service Center by 11,183 square feet. The new facility is designed with a larger footprint to address multiple deficiencies at the existing facility that negatively impact gas operations including insufficient space for crew rooms, parts and material storage, welding operations, and automotive tools and repairs. Even at 23,500 square feet, however, the projected building area of the new Hastings Service Center, based on conceptual data, is smaller than many of the Company's Service Centers.

Q. What type of operations departments will work at the new Hastings Service Center as compared to the existing Hastings Service Center?

A. The existing Hastings Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; IT (Information Technology); Electric Operations; and Shared Services. The Company anticipates the new Hastings Service Center will house many of these same operations.

Q. Approximately how many employees will work at the new Hastings Service Center as compared to the existing Hastings Service Center?

A. The existing Hastings Service Center houses approximately 50 employees. The Company anticipates the New Hastings Service Center will house a comparable number of employees with a portion of these employees having a hybrid work arrangement, requiring only collaborative space, and using office desk space with open seating in the facility when they are on-site to work with other personnel.

Q. How much did the Company invest in the Hastings Service Center project in the historical year in this case?

A. In the 2023 historical year in this case, the Company invested $4,000 (gas allocation) in this project. See Exhibit A-69 (QAG-3).

Q. How much does the Company project to invest in the Hastings Service Center Project in the bridge period and test year in this case?

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $114,000 (gas allocation) in the Hastings Service Center in the 22-month bridge period.

Q. How have these projected costs been derived?

A. These projected costs represent the cost the Company anticipates to complete acquisition of the aforementioned parcel to the south in the fourth quarter of 2024. Acquisition of this parcel will allow for expansion of the existing Hastings site and construction of the new facility.

Q. What is the status of the construction of the Hastings Service Center at the time of this filing?

A. Conceptual plans and cost estimates for the project have been developed. The Barry County Road Commission (owner of the adjacent parcel to the south) has approved the Company's conceptual plan for development of the parcel and the Company now anticipates completing acquisition of the parcel in the fourth quarter of 2024. A Phase 1 Environmental Study has been completed and a Phase 2 Environmental Study will be conducted ahead of design and construction of the facility.

Q. Please describe the Gas Construction Project.

A. A complete description of the Enhanced Infrastructure Replacement Program ("EIRP") and its overall goals is outlined in the direct testimony of Company witness Kristine A. Pascarello. To support Company crews and contractor resources performing replacement of pipe and main assets as part of EIRP, the Company has identified and leased six facilities that will be used to store equipment, vehicles, and other assets used in EIRP. These six facilities will also serve as operation hubs to which EIRP Company crews and contractor resources will report for the duration of the EIRP project in those geographic areas.

Q. Where are the facilities being used as EIRP reporting and operation hubs located?

A. The six facilities being used as EIRP reporting and operation hubs are located as follows:

Location	Address
Holly Gas Construction	4100 East Baldwin Road, Grand Blanc, MI 48139
Jolly Road Construction	1500 East Jolly Road, Lansing, MI 48910
Midland Gas Construction	1850 Bay City Road, Midland, MI 48642
Madison Heights Gas Construction	111 East 12 Mile Road, Madison Heights, MI 48071
Macomb Gas Construction	27432 Groesbeck Highway, Roseville, MI 48066
Saginaw Gas Construction	2119 River Street, Saginaw, MI 48601

Q. How much does the Company project to invest in the Gas Construction Project in the bridge period and test year in this case?

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $6,089,000 in the Gas Construction Project in the 22-month bridge period.

Q. How have these projected costs been derived?

A. Construction management firms were engaged to develop and prepare design programs and construction schedules for the Gas Construction Project, which were then used to develop project cost estimates.

Q. What is the status of the construction of the Gas Construction Project at the time of this filing?

A. See chart below.

<u>Gas Construction Project Milestones</u>

Location	Procurement / Permits / Approvals	Construction / Renovation	Closeout	Current Status
Holly Gas Construction	October 2023 - November 2023	November 2023 - May 2024	July 2024 - October 2024	In Closeout
Jolly Road Construction	October 2023 - December 2023	December 2023 - October 2024	October 2024 - December 2024	In Construction
Midland Gas Construction	November 2022 - December 2022	January 2023 - August 2023	September 2023 - December 2023	Complete
Madison Heights Gas Construction	August 2022 - October 2022	November 2022 - April 2023	May 2023 - August 2023	Complete
Macomb Gas Construction	November 2022 - December 2022	January 2023 - May 2023	June 2023 - July 2023	Complete
Saginaw Gas Construction	April 2023 - June 2023	June 2023 - July 2024	Auugust 2024 - October 2024	In Closeout

<u>Renovations</u>

Q. What capital expenditures are included in the Renovations portfolio category?

A. The Renovations portfolio category includes major modifications to the interior and/or exterior of existing facilities (e.g. adding a garage to a building). As shown in Exhibit A-69 (QAG-3), the Company is projecting to spend $11,446,000 (gas allocation) on Renovations in the 22-month bridge period and $3,280,000 (gas allocation) on Renovations in the test year.

Q. Has the Company identified projects in the Renovations portfolio category?

A. Yes. As shown in Exhibit A-69 (QAG-3), the Company has identified the following Renovations projects within projected bridge period and test year costs:

- Kalamazoo Service Center
- Jackson Dispatch
- Electric Vehicle ("EV") Infrastructure

Q. Describe the Kalamazoo Service Center project.

A. In this project, the Company is renovating the existing Kalamazoo Service Center. The Company will remediate environmental concerns, workspace concerns, and problems with aging building systems at the existing facility upon completion of this renovation. The renovations of this facility will entail adding insulation to exterior walls, installation of new exterior doors and windows, new roofing membrane and roof insulation, new interior finishes, new furnishings, new plumbing fixtures and fittings, new HVAC equipment and ductwork, and new energy efficient lighting systems.

Q. What alternatives to the renovation of the Kalamazoo Service Center did the Company consider?

A. The Company considered the following three alternatives: (1) do nothing; (2) renovate the existing Kalamazoo Service Center; and (3) demolish the existing building and construct a new building on site. The option to renovate was identified as optimal. See Exhibit A-70 (QAG-4).

Q. How did the Company decide to renovate the existing service center?

A. The Company originally planned to construct a new facility on the existing property, as discussed in Case No. U-20963. In Case No. U-20963, the Company's projected total cost for the new Kalamazoo Service Center was $52 million. After reevaluating its original plans, the Company found additional cost savings. The Company's updated projected total cost for the new Kalamazoo Service Center is now $35 million, an approximate 33% reduction in cost (see Exhibit A-69 (QAG-3)). The Company determined that a renovation would meet its workforce needs and provide better value for customers by minimizing the scope of architectural work required to achieve needed improvements in the facility. A renovation of the existing Kalamazoo Service Center will maximize utilization of the building's existing space, while minimizing disruptions to the Company's operations. Specifically, a renovation will minimize disruptions both to areas that house the Company's operating crews and to areas where the equipment and vehicles that crews use to service customers are maintained and serviced. Other considerations supporting the decision to renovate the existing facility include the fact that the Kalamazoo Service Center is already optimally located for responding timely to the Company's customers and a renovation will yield an estimated 10% reduction in energy use (see Exhibit A-70 (QAG-4)).

Q. Why is doing nothing not a viable option at this location?

A. As shown in Exhibit A-70 (QAG-4), a Facilities assessment of the existing Kalamazoo Service Center produced a score of 46. Since this assessment was conducted, additional asbestos issues have been identified at this site (i.e., spray applied fireproofing, pipe wrap, floor tiles, etc.). All employees at this site had to be moved to the second floor of the building due to air quality issues rooted in the growth of mold and related asbestos concerns on the first floor. This limited space was inadequate for the Company's Electric and Gas Operations partners to operate. In addition to its environmental concerns, the existing

Kalamazoo Service Center was constructed in 1965, and its continuing use is inadequate due to aging infrastructure. Most of the existing systems throughout the facility are now over 50 years old and beyond their useful life. The space requirements of the existing workforce have changed as more personnel adopt a hybrid work arrangement requiring only collaborative workspace and transient shared office space when they are in the office working collaboratively with others. Finally, the existing Kalamazoo Service Center is optimally located for responding timely to the Company's customers (see Exhibit A-70 (QAG-4)) and, therefore, remaining at the current location best supports the Company's intent to provide timely service to its customers in the Kalamazoo area.

Q. What energy efficiency and waste reduction measures does the Company plan to install at the renovated Kalamazoo Service Center?

A. The renovated Kalamazoo Service Center is planned to be designed and constructed to achieve certification under the USGBC, LEED version 4 rating system.

Q. How much did the Company invest in the Kalamazoo Service Center project during the historical year of this case?

A. The Company invested $407,000 (gas allocation) in this project during the 2023 historical year in this case. See Exhibit A-69 (QAG-3).

Q. How much does the Company project to invest in the Kalamazoo Service Center project in the bridge period and test year in this case?

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $10,949,000 (gas allocation) in the Kalamazoo Service Center in the 22-month bridge period and $3,080,000 (gas allocation) in the test year.

Q. How have these projected costs been derived?

A. A construction management firm has been engaged to develop and prepare a detailed design program and construction schedule for the Kalamazoo Service Center project. This firm has evaluated the design program and construction schedule to develop project cost estimates.

Q. What is the status of the renovation of the Kalamazoo Service Center at the time of this filing?

A. The Company has bid and awarded a contract for construction management services and a contract for architectural and engineering design services. Architectural and engineering design work on the project is complete and the Company has begun construction/renovation of the facility.

Q. Is the projected size of the renovated Kalamazoo Service Center larger or smaller than the existing Kalamazoo Service Center?

A. The size of the renovated Kalamazoo Service Center is not projected to vary significantly from the size of the existing Kalamazoo Service Center because there is no anticipated change in the overall footprint of the facility.

Q. What type of operations departments will work at the renovated Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?

A. The existing Kalamazoo Service Center houses the following operations: Customer Experience; Gas Operations; Enterprise Project Management/Environmental Services; Information Technology (IT); Electric Operations; Shared Services; and Public Affairs. The Company anticipates personnel from some (not all) of these operating groups to be housed in the renovated Kalamazoo Service Center.

Q. Approximately how many employees will work at the renovated Kalamazoo Service Center as compared to the existing Kalamazoo Service Center?

A. Approximately 250 employees are assigned to the existing Kalamazoo Service Center. The Company anticipates the renovated Kalamazoo Service Center will house the majority (not all) of these employees with some employees adopting a hybrid work arrangement and requiring only collaborative space and using office desk space with open seating in the facility when they are on-site to work with other personnel.

Q. Please describe the Jackson Dispatch project.

A. The Company's Gas Dispatch and Electric Dispatch Centers in Jackson shared a common workspace. This shared space was also utilized by temporary storm response personnel during storm response events which resulted in confusion and miscommunication within and among the dispatch groups and storm response personnel. Company crews, for instance, had reported difficulty communicating with dispatch personnel during storms because of background noise in the Dispatch Center which introduced an unnecessary risk of human performance error. Additionally, the existing HVAC system was unable to support the cooling load of personnel and equipment working in this space, especially during storm response events. Renovation of the Jackson Service Center second floor will provide a new space to house the Gas Dispatch center while leaving the remaining space for dedicated use by Electric Dispatch and storm event personnel. The Electric Dispatch and area for storm response personnel received new permanent supplemental cooling to meet the increased demand during full occupancy and storm response events. Modifications have been made to the existing HVAC system to better serve the renovated Gas Dispatch area.

Q. What alternatives to the renovations of this space did the Company consider?

A. The Company considered the following three alternatives: (1) do nothing; (2) subdivide existing space; and (3) reconfigure space for Gas Dispatch and provide permanent supplemental cooling for the Electric Dispatch area and area for storm response personnel. The third option was identified as optimal.

Q. Why did the Company choose to renovate these spaces in the Jackson Service Center?

A. As discussed above, the space shared by the Company's Gas Dispatch and Electric Dispatch centers in Jackson was inadequate for two primary reasons. First, the space as formerly configured was suboptimal as the area often became congested (especially during storm response events) resulting in confusion and miscommunication within and among gas and electric dispatch groups and storm response personnel. Second, occupant load within the space exceeded available HVAC system cooling capacity resulting in overheating and severe discomfort among Dispatch personnel. The risk of confusion and miscommunication between Gas and Electric Dispatch personnel and Company crews represented an unnecessary safety risk to both Company crews and the public. These facts ruled out the "do nothing" option. Subdividing the shared space coupled with the use of temporary cooling equipment was determined to be insufficient to properly condition the space and represented a long-term cost. The Company, therefore, opted to reconfigure the space and provide permanent supplemental cooling to meet the variable cooling load in the space.

Q. What benefits will this renovation provide for customers?

A. Renovating this space shared by the Company's Electric and Gas Dispatch groups will improve communication between Gas Dispatch personnel and Company crews resulting in improved gas leak response. Improved communication will reduce the risk of safety incidents for both Company Gas crews and the public.

Q. How much does the Company project to invest in the Jackson Dispatch project in the bridge period and test year in this case?

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $156,000 (gas allocation) in the Jackson Dispatch Project in the 22-month bridge period.

Q. What is the status of the renovation of the Jackson Dispatch area at the time of this filing?

A. The Jackson Dispatch Project is complete.

Q. Has the Company invested capital in the Jackson Dispatch renovation thus far?

A. Yes. In the 2023 historical year of this case, the Company invested $302,000 (gas allocation) in the project.

Q. Please describe the Electric Vehicle Charging Infrastructure project. What are its overall goals?

A. As outlined in the direct testimony of Company witness Corey E. Ballinger, the Company has a strategy to electrify portions of its vehicle fleet by purchasing EVs for Company use. As Company witness Ballinger discussed, the Company is currently acquiring EVs. To ensure these EVs are available for Company crews to use in serving customers, the Company must construct adequate charging infrastructure at sites where these vehicles will be maintained.

Q. At which Company sites will EVs purchased in the bridge period and the test year be maintained?

A. The Company sites at which EVs purchased in the bridge period and test year will be maintained is outlined in the direct testimony of Company witness Ballinger.

Q. How much capital is the Company projecting to invest in the Electric Vehicle Charging Infrastructure project in the bridge period and test year in this case and for what purpose?

A. As shown in Exhibit A-69 (QAG-3), the Company is projecting to invest $341,000 (gas allocation) in the Electric Vehicle Charging Infrastructure project in the bridge period and $199,000 (gas allocation) in the test year. The purpose of this investment is to provide the electric infrastructure upgrades and charging station installations required to support EVs purchased in the bridge period and test year as outlined in the direct testimony of Company witness Ballinger.

Q. How were these costs determined?

A. Cost estimates were developed for electric infrastructure upgrades and charging station installations required to support EVs purchased in the bridge period and test year utilizing historical cost data from similar projects.

<u>O&M Spending Overview</u>

Q. What is included in the projected O&M expenses for Gas Operations Support?

A. The Company is projecting to spend $9,525,000 in Gas Operations Support for the test year. This spending is allocated between Facilities, Real Estate, and Supply Chain. Total Gas Operations Support O&M expenses included in Exhibit A-68 (QAG-2) for the test year were established at a level not to exceed total Gas Operations Support O&M expenses for the historical year in this case.

Q. What O&M expenses are included in "Facilities," line 1 in Exhibit A-68 (QAG-2)?

A. Facilities work includes items such as maintenance and repair of HVAC systems, miscellaneous building repairs, yard maintenance and snow removal, and daily cleaning or other major scheduled cleaning projects such as windows and carpeting.

Q. What O&M expenses are included in "Real Estate," line 2 in Exhibit A-68 (QAG-2)?

A. Real estate services includes a variety of real estate asset management functions to ensure system integrity and safeguarding of the public. This includes management of all land-related uses of easements and rights of way, including encroachments, third-party requests for use of Company property, landowner requests for modification of easement rights or approval of permission to construct within an easement, as well as management of all corporate facility leases. The group also responds to all requests to sell property or grant easements, leases, or licenses to third parties. Included in real estate services is the records management function that is responsible for maintenance of a land inventory and Geographic Information System mapping for property ownership and rights of way.

Q. What O&M expenses are included in "Supply Chain," line 3 in Exhibit A-68 (QAG-2)?

A. Supply Chain assists with vendor and contractor management, purchasing of materials and services, document reproduction, and internal mail distribution.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

KIRKLAND D. HARRINGTON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Kirkland D. Harrington, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Tariff Analyst in the Rates and Regulation Department.

Q. Please describe your educational background.

A. I received a Dual BBA in Marketing and Management in June 2010 from Northwood University.

Q. Please describe your work experience at Consumers Energy.

A. In March 2013, I was hired by Consumers Energy as a Customer Service Representative within the Company's call center. In May 2017, I accepted a role as a Customer Service Revenue Recovery Assistant within the Energy Assistance department. In November 2018, I accepted a role as a Technical Assistant within Gas Distribution Scheduling where my duties included ensuring proper permitting and safe access to work sites by facilitating coordination between local municipalities and governmental departments. In December 2022, I joined the Rates and Regulation department as a General Rate Analyst in the Rate Administration section. In June 2023 my position title was updated to Tariff Analyst.

Q. Please describe your responsibilities as a Tariff Analyst.

A. My responsibilities include development and implementation of the Company's tariffs. I also perform regulatory research, prepare rate comparisons, review Commission orders, and legislation.

Q. Have you previously provided testimony before the Commission?

A. Yes. I have sponsored the Company's proposed tariff changes and rate schedules in general gas rate Case No. U-21490. In addition, I have filed direct testimony in Case No. U-21387 supporting the tariff exhibit of the Company's proposed voluntary Renewable Natural Gas Program, and Case No. U-21321 supporting the tariff exhibit for the Company's 2024-2025 Energy Waste Reduction Plan.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to present the Company's proposed tariff language changes to its gas rate schedules.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-71 (KDH-1)		Summary of Tariff Changes; and
Exhibit A-16 (KDH-2)	Schedule F-5	Proposed Tariff Sheets (MPSC No.3 Redlined Version).

Q. Were these exhibits prepared by you or under your direction?

A. Yes.

Q. Please describe Exhibit A-71 (KDH-1) – Summary of Tariff Changes.

A. Exhibit A-71 (KDH-1) provides a summary and explanation of the tariff changes proposed in this filing to the tariffs in the Company's Gas Rate Book.

Q. Please describe Exhibit A-16 (KDH-2), Schedule F-5, Proposed Gas Tariff Sheets (MPSC No. 3 Redlined Version).

A. Exhibit A-16 (KDH-2) Schedule F-5, contains, in redlined format, all proposals the Company is making in this case to its current gas tariffs in the Company's Rate Book for Gas Service (MPSC No. 3 – Gas). Existing tariff language proposed for deletion is indicated by red strikethrough formatting. New tariff language being proposed is indicated by blue, underline, italicized formatting. Some of these changes are discussed in the testimony of other Company witnesses. For example, the rationale for price changes to the Company's gas rate schedules are supported by the Company's rate design witness, S. Austin Smith.

Q. Please explain the proposed changes Rule C8.B., Customer Contribution on Tariff Sheet No. C-37.00.

A. The Company has a winter construction period from December 15 to April 15 in which additional charges based on periodic reviews of actual costs incurred are applicable. The Company's proposed tariff language is adding the ability for the Company to waive winter construction charges, partially or completely, at the Company's discretion for certain projects or sites that allow for efficient construction.

Q. Please explain the changes on Tariff Sheet No. C-40.00.

A. On Tariff Sheet No. C-40.00, the Company proposes changing the carrying cost rate to 9.11% and the discount rate to 7.35%. This change is further detailed in Company witness Smith's Exhibit A-16 (SAS-2), Schedule F-2.1.

Q. Please explain the proposed changes to General Service Outdoor Lighting Rate GL on Tariff Sheet Nos D-2.00, D-2.10, D-2.30, D-9.00, and D-14.00.

A. These tariff sheets reflect the termination of General Service Outdoor Lighting Rate GL (Rate GL). All remaining gas streetlights on Rate GL will have been retired or scheduled for retirement such that no gas streetlights on Rate GL will be in service on and after November 1, 2025. Rate GL has been closed to new business since December 23, 1971, as authorized in Case No. U-3907.

Q. Please explain the changes on Tariff Sheet Nos. D-9.00, E-13.00, and E-14.00.

A. These tariff sheets reflect the revision of Transmission Only Transportation Service Rate TOT to four rate options of STT, LTT, XLTT and XXLTT with both a Customer Charge and a Transportation Charge as proposed in direct testimony by Company witness Smith.

Additionally, the Company is proposing to exclude power generation customers from taking Transmission Only Transportation Service Rate TOT. Power generation customers have a different load profile than what was planned for in the Transmission Only Transportation Service Rate TOT.

Q. Please describe proposed modifications to the Group Transportation Service Pilot Program located on Tariff Sheet Nos. A-6.00, G-1.00 through G-3.00, G-5.00, G-6.00, and G-8.00 through G-11.00.

A. The Group Transportation Service Pilot Program was authorized in Case No. U-20439 effective for service rendered on and after October 1, 2020. With the initial five-year pilot development timeframe reaching completion, the Company is proposing elimination of the word Pilot from the program name, updating all references to the program to "Group Transportation Service Program" throughout the Company's Gas Rate Book.

Q. Are there any other tariff changes being proposed by the Company?

A. Yes. The remainder of the Company's proposed tariff changes are described in Exhibit A-71 (KDH-1), Summary of Tariff Changes. The exhibit provides a summary and explanation of all the tariff changes being proposed by the Company in this case.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

TIMOTHY K. JOYCE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Timothy K. Joyce, and my business address is 17000 Croswell Street, West Olive, Michigan 49460.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Senior Strategy Manager in the Gas Engineering and Supply Department.

Q. Please describe your educational background.

A. In 2000, I received a Bachelor of Science Degree in Mechanical Engineering from Purdue University. In 2014, I received a Master of Business Administration Degree from Grand Valley State University.

Q. Please describe your business experience.

A. My professional working career began in 2001 as a Boiler Engineer for Consumers Energy. In this position, I performed boiler inspections and contractor oversight/weld quality during maintenance outages. In 2003, I joined the Operations Department as a Production Engineer at the J.H. Campbell ("Campbell") Plant. In this position, my responsibilities included troubleshooting of equipment, filling in as a shift supervisor and acting as backshift outage manager. In 2007, I accepted a position as Production Lead at Campbell. In this position, my responsibilities included management of day-to-day operations at Campbell Units 1 and 2. In 2008, I moved into a Gas Compression Engineer position for Consumers Energy. My responsibilities included engineering and construction of new compressor stations at White Pigeon Compressor Station ("White Pigeon") Plant 3 and Ray Natural Gas Compressor Station ("Ray") Plant 3.

In 2011, I accepted the position of Project Lead Engineering on the Air Quality Control System project for Campbell Units 1 and 2. This role involved leading the engineering, procurement, installation, and start-up of air emissions reduction equipment on each unit.

In 2016, I moved into my current role of Senior Strategy Manager. In this position, my responsibilities include asset lifecycle oversight, guidance and leadership of the Natural Gas Delivery Plan ("NGDP"), implementation, recovery and verification of results focused on the Company's investment and operation of compression and storage assets.

Q. Have you testified in other cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have recently provided testimony in Case No. U-20322, Case No. U-20650, Case No. U-21148, Case No. U-21308, and Case No. U-21490. In these cases, I have provided testimony and exhibits concerning capital investments for the Company's Gas Compression and Gas Storage assets, operating and maintenance costs for the Company's Gas Compression, Lost and Unaccounted for ("LAUF") Gas, Company Use Gas expenses, Storage Field Inventories and Cost of Gas Sold.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony explains the Company's request for rate relief as it relates to the Company's Gas Compression & Storage ("GCS") assets, and I have divided my direct testimony into five parts:

(i) A description of the Company's GCS assets;

(ii) A description of functions within Gas Compression and Gas Storage;

(iii) A description of Operation and Maintenance ("O&M") expenses for Compression, Cost of Gas Sold and Underground, LAUF and Company Use Gas for the years 2023 through the projected test year (November 1, 2025 through October 31, 2026). (**NOTE:** Storage O&M is addressed by Company witness James P. Pnacek);

(iv) A description of GCS capital expenditures (including the Freedom Compressor Station ("Freedom") upgrade project) for the years 2023 through the projected test year (November 1, 2025 through October 31, 2026) base; and

(v) A description of certain Information Technology ("IT") Projects that support gas compression operations.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-72 (TKJ-1)		12 Months Ending October 31, 2026 Gas Compression and Renewable Natural Gas O&M Expenses;
Exhibit A-73 (TKJ-2)		Summary of Actual & Projected Gas O&M Expenses for Lost and Unaccounted for Gas & Company Use Gas for the Test Year 12 Months Ending October 31, 2026;
Exhibit A-74 (TKJ-3)		Calculation of Gas Loss Percentage August 2019 through July 2024;
Exhibit A-75 (TKJ-4)		Calculation of Allowance for Gas Use and Losses for the Test Year 12 Months Ending October 31, 2026;
Exhibit A-12 (TKJ-5)	Schedule B-5.7	Projected Capital Expenditures Gas Compression and Gas Storage Summary of Actual & Projected Gas Capital Expenditures;
Exhibit A-76 (TKJ-6)		Storage Well Rehabilitation Program Detail; and
Exhibit A-77 (TKJ-7)		Storage Fields Month End Summary.

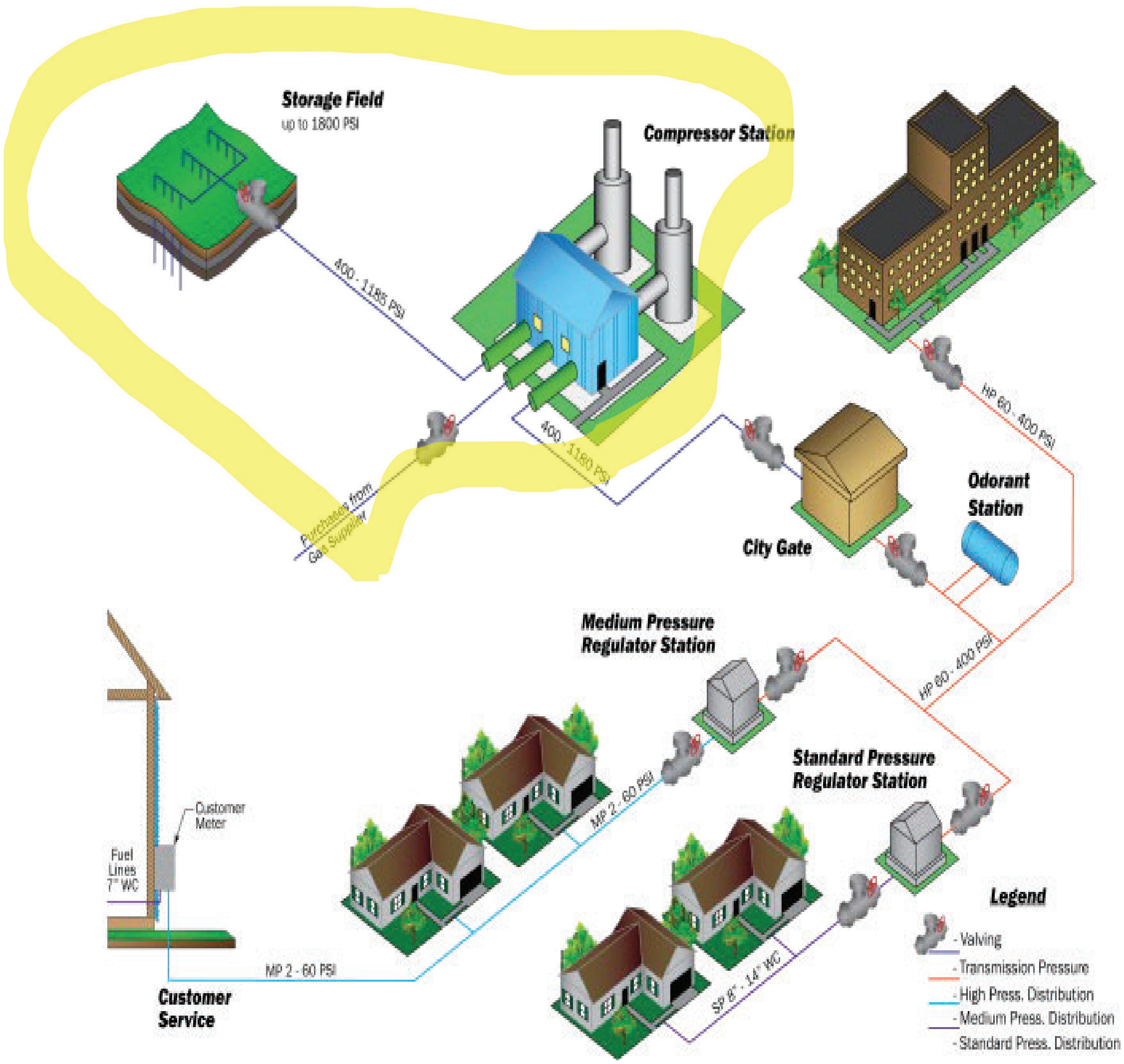
Q. Were these exhibits prepared or assembled by you or under your direction or supervision?

A. The exhibits listed above were prepared either by me or under my direction and supervision.

(i) <u>GCS ASSETS</u>

Q. Please provide an overview of the Company's GCS assets.

A. The Company operates and maintains 8 compressor stations, 15 storage fields, and 808 wells as of January 2024, throughout Michigan's Lower Peninsula. As of October 2024, the compression fleet is comprised of 40 natural gas-fired engines which generate 147,393 Brake Horsepower ("BHP"), providing the pressure necessary to move gas in and out of the storage fields and to receive supply from interstate pipeline sources onto the Company's transmission pipeline system. The transmission pipeline system connects the gas supplies to Consumers Energy's storage fields, gas distribution system, and other customer loads. In the diagram below, the Storage and Compression systems are inside the yellow highlighted section.



The Company's storage fields are used to balance the difference between the incoming system supplies and customer demand on a continuous, real-time basis. The storage fields are naturally occurring porous rock formations that are located deep underground. These rock formations hold natural gas, much like sponges hold water, and have a total working gas volume of 154 BCF. Consumers Energy purchases 100% of the natural gas it provides to customers. Natural gas, which is placed in storage, flows through one or more of the Company's numerous wells. The Company's GCS fleet is comprised of the following:

Compressor Stations:

Name	Location	Number of Units	Horsepower (BHP)
Freedom	Manchester, MI	5	18,750
Muskegon River	Marion, MI	7	27,276
Northville	Northville, MI	4	10,800
Overisel	Hamilton, MI	4	10,800
Ray	Armada, MI	5	23,675
St. Clair	Ira, MI	6	27,282
White Pigeon	White Pigeon, MI	8	27,775
Huron	Sebewaing, MI	1	1,035

Gas Storage Fields:

Type	*Storage Field Name*	*Working Gas Volume (Bcf)**	*Base Gas Volume (Bcf)**	*Total Gas Volume (Bcf)**	Number of Wells	Max Field Rate (MMcfd)**
Base	Winterfield	25.30	47.00	72.30	249	266
	Overisel	25.50	27.50	53.30	152	230
	Salem	11.60	18.90	30.50	71	130
	Cranberry	11.00	17.20	28.20	129	106
	Riverside	1.50	7.50	9.00	51	13
Intermediate	Hessen	13.50	3.48	16.98	24	455
	Puttygut	9.50	5.10	14.60	24	310
	Four Corners	2.39	1.39	3.78	6	68
	Swan Creek	0.42	0.23	0.65	1	20
	Ray	48.10	17.27	65.37	62	1975
Peaker	Ira	2.00	4.25	6.25	15	480
	Lyon 29	1.23	0.95	2.18	3	270
	Lenox	1.20	2.03	3.23	11	247
	Lyon 34	0.70	0.66	1.36	5	120
	Northville Reef	0.50	0.72	1.22	5	210
****NOTE:*** All gas volumes are in MMcf at 14.73 psi dry pressure base.						
*****NOTE:*** Max Field Rate is the maximum capability at full inventory and pressure and would decline over the withdrawal season and depend on the final inventory level at the beginning of withdrawal.						

(ii) GAS COMPRESSION AND STORAGE

Gas Compression

Q. Please describe the primary functions of gas compression.

A. Gas compression is responsible for the safe operation, maintenance, and performance of the Company's natural gas-fired engines. These units provide the pressure necessary to move gas in and out of the storage fields, to move gas from interstate pipeline sources onto the Company's transmission pipeline system, and ultimately, to move the natural gas to the city gate facilities feeding distribution systems that transport gas to the Company's customers.

Q. Do maintenance costs vary by individual compression engine(s)?

A. Yes, maintenance costs vary by individual compression engine(s). The Company's compression engines vary in age, size, type, and design and encounter varying operating conditions.

Q. Is it common to have size, type, design, and operating differences?

A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type, and design. The compression engines used for storage will typically encounter a wider range of operating pressures and flow rates than engines used to boost pressure on the transmission system.

Q. Please describe the work completed in a natural gas compressor engine maintenance inspection.

A. The frequency of compressor engine inspections is based on operating hours, and consists of disassembling, inspecting, and cleaning the different components of the engine. During the inspection, worn or damaged parts are repaired or replaced to specific tolerances. Cost can range from $25,000 to $75,000 per inspection, depending on the size and model of the unit. Additional costs can occur if parts are found to be worn and require replacement before resulting in random outages at inopportune times when needed to meet system demand.

Q. How does Consumers Energy measure the success of its Gas Compressor Engine Maintenance Program?

A. The Company measures Random Outage Rate ("ROR") to measure engine/compressor performance. ROR is the percentage of time a unit is unavailable for unplanned reasons.

Q. What is the Company's current ROR, and how does it compare to previous years?

A. The table below shows the Company's ROR from 2020 through September 2024.

Table 1: System ROR

Year	System ROR
2020	17.5%
2021	15.6%
2022	8.4%
2023	11.6%
2024 (YTD Sept)	19.2%

Table 2: Freedom, Ray and White Pigeon Station ROR

Year	Freedom Station ROR	Ray Station ROR	White Pigeon Station ROR
2019	21.8%	38.2%	21.5%
2020	21.7%	17.7%	25.5%
2021	27.0%	16.5%	25.1%
2022	13.2%	10.6%	9.2%
2023	11.7%	15.9%	4.3%
2024 (YTD Sept)	15.1%	9.1%	6.1%

Q. What has contributed to the improved ROR performance in 2023-24 in Table 2 and what is needed for the Company to be able to achieve and maintain its engine performance?

A. The Freedom upgrade project is completed, and all legacy horsepower have now been removed from service, as detailed later in my testimony. Retirement of units at White Pigeon and Ray occurred in 2021. The effort to optimize the compression fleet has provided improved performance of the newer units and removal of the lower performing legacy units, which has netted an improvement in ROR for 2023-24.

To improve the ROR of the remaining compression fleet and, consequently, reduce downtime and overall maintenance costs, the Company will enhance maintenance plans and practices to achieve more efficient preventative programs and eliminate costly reactive events.

Q. Please describe the Company's objectives for gas compression assets.

A. The Company's objective for its gas compression assets is to realize the most value out of the Company's substantial storage capacity in terms of resilience and buffering summer/winter price fluctuations. Continually improving the safety of compression assets and reducing operational risks is critical. Beginning in 2010, the Company made significant progress transforming the compression fleet from 1950s technology to modern, efficient, and clean running equipment. The Company's objectives for Compression of improving the system's reliability, resiliency and optimal utilization are:

a. Accelerate the implementation of preventative maintenance program and practices, and gradually implement predictive technologies.

b. Decommission retired/mothballed compressor units.

c. Optimize the fleet of compressor units at Muskegon River to meet volume and pressure requirements.

d. Evaluate contingency options for resiliency and opportunities that mitigate risk of outages at the compression stations.

e. Assess feasibility of retiring additional compression assets to focus investment on most critical units and optimize portfolio.

f. Compressor Station Compliance with Proposed Michigan NOx RACT Rule.

Q. Does the NGDP discuss gas compression assets?

A. Yes, gas compression is addressed in Section IV of the Company's NGDP, which is provided as Exhibit A-42 (NPD-1) by Company witness Neal P. Dreisig.

<u>Gas Storage</u>

Q. Please describe the primary functions of Gas Storage Engineering.

A. Gas Storage Engineering has responsibility for the integrity, maintenance, and performance of the Company's 15 storage fields and 808 wells. This includes storage well maintenance and well logging and compliance with well integrity regulations. Further details about Gas Storage Engineering O&M expenses are included in Company witness Kristine A. Pascarello's testimony.

Q. Please provide further insight into well maintenance.

A. Well maintenance is comprised of many different programs and has been the topic of media attention in recent years with the Aliso Canyon event. Well logging is one of the primary components of well maintenance. *Well logging* is an industry term that describes a method used to help assess storage well integrity. Storage well integrity is a critical component to ensuring public safety.

Q. Please provide more detail on well logging.

A. Well logging includes the use of gamma ray-neutron log for identification of gas accumulation behind casings, corrosion logs for internal and external casing corrosion, and cement bond logs to assess integrity of cement between the casing, surrounding rock, or additional casings. Additionally, well rehabilitation work is performed in conjunction with well logging to mitigate the formation of skin damage. *Skin damage* is a term used to describe the reduction in the ability of the reservoir rock to store and deliver gas. Rehabilitation removes solids, scale build-up, and compressor oils in the well that accumulated during the normal process of injecting and withdrawing gas from storage. By removing this build-up, the gas moves more efficiently and reduces the risk of moving debris into the compressors, thereby increasing safety and extending the life of the assets.

Q. Do storage well integrity regulations currently exist?

A. Yes. On December 19, 2016, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") published in the Federal Register an interim final rule ("IFR") that revises the federal pipeline safety regulations to address critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities. This IFR was in response to the June 22, 2016, enactment of the Protecting our Infrastructure of Pipelines and Enhancing Safety ("PIPES") Act of 2016 that included a requirement for PHMSA to set federal minimum safety standards for underground natural gas storage facilities. Requirements included in the IFR were amended to final rule by PHMSA on February 12, 2020.

Q. Did PHMSA set federal minimum safety standards?

A. Yes. PHMSA published the underground natural gas storage facilities rule (49 Code of Federal Regulations ("CFR") 192.12) which incorporates by reference the requirements within the American Petroleum Institute ("API") Recommended Practice ("RP") 1171.

Q. Is Consumers Energy compliant with the standards set forth in 49 CFR 192.12?

A. Yes. Consumers Energy has reviewed the requirements outlined in 49 CFR 192.12 and the applicable API RP 1171. The Company developed procedures governing operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping consistent with the requirements of API RP 1171, sections 8, 9, 10, and 11 by January 18, 2018, for all existing underground natural gas storage facilities. Integrity assessments of the underground storage wells began in 2017 to support the anticipated compliance timeframe, for completing all risk management activities as required in API RP 1171. The compliance date has now been set for March 2027.

Q. Has PHMSA performed an audit of the Company storage system?

A. Yes. In May 2019, PHMSA performed a program overview audit, followed by field audits, on six gas storage fields and the associated site-specific programs. The audit focused on Sections 8 through 11 of API RP 1171. In 2020, there were field specific audits at the Four Corners, Swan Creek, Hessen, Ira, and Puttygut fields. In 2021, the MPSC jointly with the Michigan Department of Environment, Great Lakes, and Energy performed field specific audits at the Riverside, Lyon 34, Lyon 29, and Northville Reef.

Q. What was the result of the 2019 audits?

A. The Company created a Detailed Action Plan based on PHMSA recommendations of best industry practice. Topics outlined in the plan include: Risk Management for Gas Storage Operations, Integrity Demonstration, Verification, Monitoring Practices, Site Security and Safety, Site Inspections, Emergency Preparedness and Response, and Procedures and Training.

Q. Were any changes made to the Well Rehabilitation Program based on the PHMSA 2019 audit recommendations?

A. Yes. PHMSA recommended the wells in the Riverside field be addressed by the program (risk priority as identified in the risk analysis) until the plan to discontinue operation of the field is executed. As a result, the Company added wells to the 2019 and future-year Well Rehabilitation Program work scopes. PHMSA also recommended the addition of annular piping to surface where casing pressures will be recorded and monitored, as per the requirement in API RP 1171. These items are now being addressed by the program as they are encountered, which has an impact on the average cost per well. The Company established a new annulus pressure monitoring program for 2022 and future years to address compliance, including the wells already rehabilitated in 2017 and 2018.

Q. Have there been any additional audits performed on the Company storage system?

A. Yes. In 2023, an audit of the Company’s SIMP program was conducted by the MPSC and EGLE. The scope of the audit included Procedures, Records, and Field Observations for Salem, Overisel, Ray, Lenox, Cranberry Lake, and Winterfield Storage Fields. At the conclusion of the audits, the company did not receive any enforcement or non-compliances and received 16 recommendations that were primarily procedural in nature and did not impact the funding required for the current test year.

Q. Is the Company projecting O&M expenses related to well logging in this case?

A. Yes. Well logging O&M expenses are sponsored by Company witness Pascarello in the well re-assessment section.

Q. Does gas storage have additional responsibilities?

A. Yes, gas storage is also responsible for the gas storage field inventory verification process.

Q. Please describe the gas storage field inventory verification process.

A. As a prudent operating practice and following the regulatory requirements of API RP 1171 as referenced in 49 CFR 192.12, Consumers Energy performs storage field pressure surveys at the conclusion of each injection cycle (usually August through November), and each withdrawal cycle (usually March through June). Storage well pressures are collected, the average field pressure is determined, and the results are plotted against the metered volumes. Plotting storage field pressure and inventory data provides a means of monitoring and trending storage field performance over time. It is through this process that the inventory balances at the storage fields are identified for adjustment.

Q. Why is the performance of storage field inventory verification a prudent practice?

A. Verification of storage field inventory after each injection and withdrawal cycle provides important data used to monitor the current condition of the storage reservoir. In addition, storage field inventory verification provides a means of determining flow meter measurement accuracy, and whether losses between the transmission and storage systems may be occurring as a result of valve leakage. Without inventory verification, there is the potential for gas to have migrated out of the storage reservoir, which would pose potential risk to public safety. In addition, if inventory is not verified and a leakage were to occur unknowingly, customers could be at risk of paying for gas that is lost.

Q. What are the recent results from the gas storage inventory verification process?

A. The storage fields have experienced deviations from the accounting booked figures. The Company typically adjusts gas storage inventory based on a deviation occurring for three consecutive years (considered long-term). Routine changes in operating parameters during a given injection or withdrawal season may cause short-term storage field pressure variations. These short-term pressure variations may cause the natural gas to migrate deeper into the reservoir rock formation, temporarily impacting the inventory survey results. Company personnel have investigated the integrity of these fields and believe most of the inventory adjustment is attributed to metering accuracy limitations or valves not sealing properly. The storage field inventory adjustment is shown in Exhibit A-74 (TKJ-3).

Q. Why does the storage inventory deviation occur?

A. A common cause of the deviations and subsequent storage field inventory adjustments can be valves not sealing properly. As part of the pressure survey work each spring and fall, the sealing capability of the valves used to isolate the storage field are inspected. The primary cause of valve leakage, as with the field meter, is debris affecting the sealing mechanisms in the valves. In addition, the electrical or hydraulic mechanical operators used to open and close the valves can go out of alignment, not allowing the valve to fully close. When storage field isolation valves are found to be not sealing, the valves are adjusted or repaired.

Q. Please describe the Company's objectives for gas storage assets.

A. The gas storage system today includes 15 storage fields totaling approximately 154 billion cubic feet of working gas storage capacity. Storage assets play an important role in customer affordability, enabling the purchase and storage of gas when prices are lower, and delivery of that gas in the winter. On average, storage has supplied approximately 50% of customer gas deliveries during winter (November through March) and up to approximately 80% on peak days. Storage also allows Consumers Energy to store or withdraw gas throughout the day to reconcile the difference between customer demand and the fixed pipeline supply.

As part of the NGDP (and in view of the PHMSA Storage Audit based on API RP 1171), the Company ran an initial assessment on four of the low-cyclic fields with the results showing the need to consider the retirement of at least one storage field at this time. Based on the outcome of this initial assessment, Consumers Energy has evaluated retirement and optimization of its storage fields over time based on certain factors like customer load, market price changes over time, increasing operating costs, reliability, and total cost to customers. The Company has made the decision to move forward with the sale of Riverside storage field; further details and projected expenses are outlined later in my testimony. With the remaining storage portfolio, Consumers Energy will remain focused on reliable operation, increasing resiliency, while optimizing deliverability.

Q. Does the NGDP discuss gas storage assets?

A. Yes. Gas storage is addressed in Section IV of the Company's NGDP, which is provided as Exhibit A-42 (NPD-1) by Company witness Dreisig.

Q. What value do customers receive from the Company's GCS assets?

A. GCS assets support the Company's ability to ensure adequate supplies of natural gas are available for customers when needed. They are also an important foundation to maintaining affordable prices, as they allow the Company to take advantage of favorable seasonal market conditions, while procuring adequate supplies in advance to meet customers' needs. Finally, storage fields are critical to mitigating winter price cycles, summer outage schedules, and maintaining supply during unexpected supply interruptions.

(iii) O&M EXPENSES FOR COMPRESSION, COST OF GAS, LOST AND UNACCOUNTED FOR AND COMPANY USE

Q. Please describe Exhibit A-72 (TKJ-1).

A. Exhibit A-72 (TKJ-1) identifies the 12 Months Ending October 31, 2026, Gas Compression and Renewable Natural Gas O&M Expenses. Specifically:

- Page 2, column (a) identifies each O&M expense category;
- Page 2, column (b) identifies the Actual 2023 Gas Compression O&M expense as $17,880,000;
- Page 2, column (c) identifies the Projected 2024 Gas Compression O&M expense as $17,030,000;
- Page 2, column (d) identifies the Projected 2025 Gas Compression O&M expense as $16,590,000; and
- Page 2, column (e) identifies the Projected test year Gas Compression O&M expense as $17,577,000.

Table 3: Compression O&M

	Projected O&M Expenses				
	(a)	(b)	(c)	(d)	(e)
				Projected	
Line		**12 mos. Ended**	**12 mos. Ending**	**12 mos. Ending**	**12 mos. Ending**
No.	**Description**	**12/31/2023**	**12/31/2024**	**12/31/2025**	**10/31/2026**
1	**Gas Compression**	18,695	17,030	16,590	17,577
2	**Compression Rebuilds**	(815)	-	-	-
4	**Renewable Natural Gas**	-	-	-	-
5	**TOTAL O&M**	**$ 17,880**	**$ 17,030**	**$ 16,590**	**$ 17,577**

Q. Please discuss the 2023 Actual O&M expenses incurred by the Company for Gas Compression.

A. The 2023 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 2024, 2025, and projected test year O&M expenses were calculated.

A. Consumers Energy tracks the history and future maintenance needs of each station. Once costs to reliably operate and comply with the Michigan Gas Safety Code are prioritized, Business Services-Portfolio Planning, with the support and input from Engineering and Asset Strategy, evaluates the maintenance plans required to maintain and improve the condition of the plant. Using this information, a preliminary plan is prepared, reviewed (to ensure high-priority issues are addressed and adequate resources and funding are available), and approved by management. The overall objective is the safe, reliable, and cost-effective operation of the Compression operations.

O&M costs projected in Exhibit A-72 (TKJ-1) were developed by evaluating a station's operating history and are broken into two categories: "labor" and "non-labor." Labor is the primary component and has a predictable increase. Non-labor expenses are also predictable and include items required to operate and execute a workplan to meet code requirements, while meeting operational performance to fulfill customer demand. These items include, but are not limited to: (i) fuel, oil and glycol for equipment and vehicles; (ii) materials; (iii) tools; (iv) cleaning supplies; (v) security; and (vi) road and grounds maintenance. Please note that Gas Storage Operations expenses are addressed by Company witness Pnacek. The test year spending was calculated using recent historical monthly actuals information.

Q. Please explain page 4 of Exhibit A-72 (TKJ-1).

A. Exhibit A-72 (TKJ-1) presents the amounts of the O&M expenses by applying either an inflation rate or a merit increase rate, or both to historical O&M expense. Column (b) shows the historical O&M expense. Column (c) shows the amount of the historical when an inflation rate or merit increase rate is applied to it. Columns (e) and (g) show the amounts when an inflation rate or merit increase rate is applied for each bridge period, respectively. Columns (d), (f), and (h) show the merit and inflation amounts for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i); column (j) is aligned with the Company's projected expenses for each sub-program for the test year, as shown in Exhibit A-72 (TKJ-1). Therefore, column (i) represents the increase in O&M expenses that is not due to inflation; in other words, this represents where O&M expenses are changing due to some other factor than inflation.

Q. Are there any Employee Incentive Compensation Program ("EICP") O&M expense dollars included in your exhibits?

A. No, there are not. The direct testimony and exhibits of Company witness Amy M. Conrad contain the Gas Transmission and Distribution EICP O&M expense dollars.

Q. Please explain why the projected test year O&M expenses proposed in Exhibit A-72 (TKJ-1) are reasonable.

A. This level of O&M expense allows the Company to provide reliable service by operating and maintaining its Compression equipment to move gas into and out of storage and throughout its system to meet the needs of customers.

COST OF GAS AND COST OF GAS STORED UNDERGROUND

Q. Please describe Exhibit A-77 (TKJ-7).

A. Exhibit A-77 (TKJ-7) is a forecast of the Company's September 2024 through October 2026 underground gas storage volumes and dollars.

Q. Would you briefly explain the background for Exhibit A-77 (TKJ-7)?

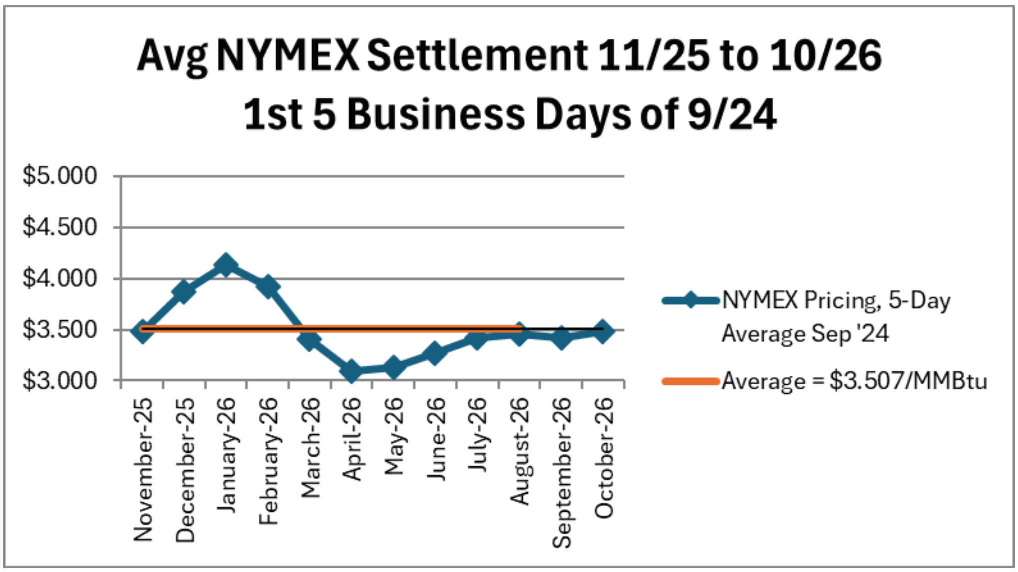
A. Yes. Exhibit A-77 (TKJ-7) reflects the end of the month underground gas storage volumes and dollars that result from the Company's natural gas purchases for its Gas Cost Recovery ("GCR") and Gas Customer Choice ("GCC") customers. The costs and volumes reflect the Company's existing supply and transportation contracts for the historical period, as well as those of the GCC suppliers. Projected supply sources and prices are used for the future periods.

Q. What is the Company's projected test year 13-month average volume and cost of gas in storage, as set forth on Exhibit A-77 (TKJ-7)?

A. Through October 2026, the Company is projecting a 13-month average cost of gas in storage of $2.949/Mcf ($382,035,501/129,554,050 Mcf).

Q. What gas prices were assumed for November 2025 through October 2026 in developing your Exhibit A-77 (TKJ-7)?

A. The average New York Mercantile Exchange ("NYMEX") settlement prices for November 2025 through October 2026, as of the first five business days of September 2024, were used. These NYMEX natural gas prices, as shown in the graph below, averaged \$3.507/MMBtu for November 2025 through October 2026.



For the November 2025 through October 2026 GCR requirements (197,455,189 Mcf), 0% has been purchased at a fixed price, therefore 100% of the GCR requirements would be subject to the NYMEX average.

Q. What is the Company's projected average cost of gas sold for October 2025 through September 2026?

A. The Company is projecting an average cost of gas sold for November 2025 through October 2026 of \$3.296/Mcf (\$754,273,924/228,868,416 Mcf). The Company's cost of gas sold reflects locational pricing differences between NYMEX (Henry Hub) and other supply locations (basis), transportation costs, unused reservation charges, and the GCR accounting treatment of net system uses. The projected average cost of gas sold is determined by including the costs and volumes associated with purchase requirements and net storage activity during the period, and thus reflects the same variables and assumptions relied on to calculate ending inventory values.

Q. Please provide additional detail about the average cost of gas sold and cost of gas stored underground.

A. Both the average cost of gas sold and cost of gas stored underground reflect the natural gas supply and transportation contracts in place within the historic period for GCR and GCC supply. The Company's existing supply and transportation contracts are planned to leverage storage and system investments in today's gas market to provide customers with safe, reliable, and affordable natural gas service pursuant to the Company's NGDP.

The cost of gas stored underground is used within the Company's projected test year working capital included in Company witness Heather L. Rayl's Exhibit A-12 (HLR-34), Schedule B-4. The average cost of gas sold of $3.296/Mcf is used in the calculation of the Company's revenue requirement and to price out Company Use and LAUF gas volumes supported later in my testimony.

<u>LAUF Gas</u>

Q. Please explain LAUF gas as shown on Exhibit A-73 (TKJ-2), line 1, column (b).

A. LAUF gas is the loss or gain of gas volumes calculated as the difference between the volumes delivered into the transmission and distribution system less the volumes delivered out of those systems. Factors such as gas leaks, customer billing issues, customer theft, meter and measurement accuracy, and gas vented for operational, maintenance, and safety purposes all contribute to the causes of LAUF gas volumes.

Q. Please describe the LAUF expenses that are projected for the test year.

A. The test year expenses related for LAUF gas are calculated based on a five-year average of actual LAUF volumes multiplied by the Company's projected commodity cost of gas. Projected LAUF expenses can be found on Exhibit A-73 (TKJ-2). As shown on that exhibit (line 1, column (c)), the test year projected LAUF expense level is $12,709,000. The 2023 historical year amount was $21,116,000 as shown in Exhibit A-73 (TKJ-2), (line 1, column (b)).

Q. Please explain Exhibit A-73 (TKJ-2).

A. This exhibit identifies the projected changes from the historical 2023 amount for LAUF expenses to the test year period. The test year LAUF amount was calculated using the methodology consistent with the July 31, 2017 Order in Case No. U-20322, updated with the most recent five-year average Gas Loss percentage and expected test year cost of gas expense, as provided earlier in my direct testimony. Additionally, this exhibit contains the Company Use Gas projected expenses for the test year. Company Use Gas will be discussed later in my direct testimony.

Q. Please explain Exhibit A-74 (TKJ-3).

A. This exhibit demonstrates the calculation of the most recent five-year average Gas Loss percentage (line 6, column (g)) of 1.79%. This percentage, when applied to test year throughput levels, determines the expected LAUF and Company Use Gas volumes during the test year.

Q. Please explain Exhibit A-75 (TKJ-4).

A. This exhibit shows the calculation of the projected test year amount of LAUF expense (line 14, column (h)) with the methodology adopted in Case No. U-20322. The test year throughput level and the updated Gas Loss percentage previously discussed have both been used to determine LAUF volumes and the associated expense levels. In addition, as shown on line 11, the Allowance for Use and Losses percentage, also known as the Gas-in-Kind ("GIK") percentage, has been updated to reflect test year projections of 2.57%.

Q. Is the level of LAUF expense the Company is requesting reasonable?

A. Yes. The Gas Loss average is based on actual losses on the gas transmission and distribution system over the past five years. The MPSC has consistently recognized a five-year average of Gas Losses to set LAUF volumes, and the Company continues to use that same methodology, updated to reflect the most recent data.

Q. Why have you included the net storage inventory adjustments in the LAUF figures as noted on Exhibit A-74 (TKJ-3)?

A. In Case Nos. U-18124 and U-20322, the Commission approved inclusion of storage inventory adjustments in the period in which they are recognized by the Company, within the five-year line loss calculation.

Q. How does the Company determine its storage inventory adjustments?

A. The Company's storage inventory adjustments are determined through the gas storage field inventory verification process. This process is described in the *Gas Storage* section of my direct testimony.

Q. What specific actions does the Company take to monitor and mitigate LAUF gas?

A. The Company has ongoing actions to monitor and reduce LAUF gas. Some of these actions include:

- A gas measurement team that primarily focuses on assuring (i) measurement accuracy and (ii) that industry practices are maintained relative to LAUF related issues. Company personnel actively participate on the American Gas

Association Transmission Measurement Committees, discussing various measurement issues;

- Measurement personnel audit and witness other Company and third-party personnel performing the regularly scheduled calibration/inspection of metering and gas quality equipment around the state. This helps ensure valid measurements and relevant procedures are followed, and also allows for identification and subsequent correction of any equipment/calibrations/ inspection-related issues;

- The Company utilizes a gas measurement system called Flow Cal monitored by the gas measurement team and field personnel to validate actual measured flows captured by the Company's data acquisition system—known as Supervisory Control and Data Acquisition; and

- The Company reviews compressor stations and high flow city gates for fugitive leaks through the use of infrared cameras and high flow analyzers. Identified leaks will be prioritized and repaired, reducing LAUF gas at those sites.

<u>Company Use Gas</u>

Q. Please describe the Company Use Gas expenses shown on Exhibit A-73 (TKJ-2), line 2.

A. These expenses are for the natural gas fuel used to run the compression and other equipment used on the transmission and storage system. The largest single use is for fueling the engines at the compressor stations and the gas heaters at the city gate stations. The total cost of fuel gas used is reduced by credits received from transportation suppliers. These suppliers provide GIK to Consumers Energy based on a percentage of their deliveries into the system. Company Use Gas also includes volumes of gas vented or otherwise released for which the Company has knowledge and which the Company has written off.

Q. What level of expense for Company Use Gas are you proposing in this case?

A. As set forth on Exhibit A-73 (TKJ-2), line 2, column (c), the Company Use Gas expense for the test year is projected to be $5,502,000. The calculation supporting this value can be found on Exhibit A-75 (TKJ-4).

Q. Why is there variability in the test year amounts for LAUF and Company Use Gas from the 2023 actual amounts?

A. In Case No. U-18124, the Commission ordered the Company to apply GIK transportation volume offsets to LAUF and Company Use Gas volumes on a percentage basis based upon the program volumes. The Company has historically offset only Company Use Gas volumes with GIK volumes, and its accounting system is currently configured to record GIK volumes against Company Use Gas volumes. Thus, the 2023 amounts are shown as recorded in the Company's internal accounting records. The test year amounts are reflective of the methodology directed in Case No. U-18124.

(iv) <u>GCS CAPITAL EXPENDITURES</u>

Q. What are the major drivers in determining capital expenditures for GCS?

A. The Company has made significant investments in upgrades for improved system reliability, deliverability, system integrity, safety, and customer service. These investments, including the Freedom upgrade, allow the Company to fully use its compression and storage facilities to provide continuous reliable service to customers.

Q. Please describe Exhibit A-12 (TKJ-5), Schedule B-5.7.

A. This exhibit presents the capital expenditures for GCS from the year 2023 through the projected test year. The expenditures are grouped on page 2 by: Freedom upgrade, Compression Sites, Storage Fields, Storage New Wells (line 14), Well Rehabilitation (line 15), Storage Pipeline Replacement (line 16), Well Data Acquisition (line 17), Riverside Field Retirement (line 18), and Safety Valve Installation (line 19).

Q. What is the Company's projected level of capital spending?

A. The Company's rate relief request in this case reflects capital spending on projects for its gas compression and storage sites of $113.0 million for 2023 (Actual), $175.3 million for the 12 months ending December 31, 2024 (Projected), $184.1 million for the 10 months ending October 30, 2025 (Projected), $359.4 million for the 22 months ending October 31, 2025 (Projected), and $162.0 million for the 12 months ending October 31, 2026 (Projected Test Year). The table below, from page 1 of Exhibit A-12 (TKJ-5), Schedule B-5.7, shows the Compression and Storage capital expenditures I am sponsoring in this docket.

Table 4: Compression and Storage Capital Expenditures ($000's)

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ended 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
1	Freedom Upgrade Project	8,413	726	0	726	0
2	Compression	39,197	62,267	44,597	106,864	66,198
3	Storage	6,765	28,548	35,690	64,238	25,234
4	New Well	11,403	17,202	28,004	45,205	32,296
5	Well Rehabilitation	31,031	23,681	22,341	46,022	7,498
6	Storage Pipeline Replacement	3,550	14,836	24,398	39,233	20,930
7	Well Data Acquisition	239	203	3,671	3,875	4,568
8	Riverside Field Retirement	12,449	25,439	23,756	49,195	3,504
9	Safety Valve Installation	0	2,438	1,599	4,037	1,811
10	Total Capital Expenditures	113,046	175,339	184,056	359,395	162,039

Q. Please identify the capital expenditures projected for the Freedom Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, lines 1 and 2, identify the total capital expenditures for the Freedom Compression Station. The expenditures identified on line 1 are for the Freedom upgrade project. The details of the Freedom upgrade project are described later in my direct testimony. The expenditures on line 2 are for projects that are separate from the upgrade project. In 2023, costs were incurred for the upgrade project.

In 2024 through 2026, costs will be incurred for the completion of the upgrade project and controller module updates that will improve engine operational stability and reliability.

Q. Please identify the capital expenditures projected for the Muskegon River Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 3, identifies the total capital expenditures for the Muskegon River Compression Station. In 2023, costs were incurred for fire gate valve replacements, replacement of dehydration system piping and installation of a glycol charcoal filter system, and installation of new plant air compressors. In 2024 through 2026, examples of projected costs include: gas valve replacements, an H-10 unit overhaul to address engine/compressor condition and performance, and a closed-loop cooling project that will eliminate the need to use Muskegon River water for equipment cooling and to further comply with 2026 EGLE discharge water temperature specifications.

Q. Please identify the capital expenditures projected for the Northville Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 4, identifies the total capital expenditures for the Northville Compression Station. In 2023, costs were incurred for the completion of electrical system upgrade, and fire gate valve replacements. In 2024 through 2026, examples of projected costs include: engine controls upgrades, replacement of engine jacket water coolers and air compressor replacement which all support the safe, reliable, and compliant operation of the station.

Q. Please identify the capital expenditures projected for the Overisel Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 5, identifies the total capital expenditures for the Overisel Compression Station. In 2023, the Company incurred costs for station control upgrades, valve replacements, and the unitized cooling project. In 2024 through 2026, examples of projected costs include: unitized cooling installation, station control upgrades, Salem field heater replacement, lube oil extractor installation and engine exhaust emissions controls, projects that allow for complete and timely withdrawal of gas from the storage fields and allow the engines to meet new Michigan NOx Reasonably Available Control Technology ("RACT") Rules emission requirements.

Q. Please identify the capital expenditures projected for the Ray Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 6, identifies the total capital expenditures for the Ray facility. In 2023, the Company incurred costs for air compressor system upgrades. In 2024 through 2026, examples of projected costs include: valve replacements, air compressor system upgrades, and piping support restoration. These projects will ensure the complete and timely withdrawal of gas from the storage fields.

Q. Please identify the capital expenditures projected for the St. Clair Compression Station.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 7, identifies the total capital expenditures for the St. Clair Compression Station. In 2023, the Company incurred costs for engine controller replacements. In 2024 through 2026, examples of projected costs include turbine gas cooler replacement, dehydration system thermal oxidizer replacement and gas blowdown vent stack replacement. These projects will ensure the complete and timely withdrawal of gas from the storage fields and safe gas blowdown when required.

Q. Please identity the capital expenditures projected for White Pigeon.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 8, identifies the total capital expenditures for White Pigeon. In 2023, the Company incurred costs for lube oil extractor installation project close out. In 2024 through 2026, examples of projected costs include air compressor replacements, turbine installation and a solar battery installation that is a green project that will reduce cost of electricity for the site.

Q. Please identify the capital expenditures projected for the Marion Storage Fields (Winterfield, Cranberry Lake and Riverside).

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 9, identifies the total capital expenditures for the Marion Storage Fields. In 2023 through 2025, the projected costs include the retirement of the Marion City Gate, which is fed from the Winterfield storage field. The retirement is made possible by the completion of the Riverside distribution piping project, which will be tied into to re-feeding customers in Marion, MI. This project will reduce operational cost, gas conditioning difficulties and operational limitations of an operating city gate fed from a storage field. An itemized list of project costs used to create Exhibit A-12 (TKJ-5), Schedule B-5.7 is included in WP-TKJ-6. A breakdown of well rehabilitation work scope is included in Exhibit A-76 (TKJ-6).

Q. Please provide more detail about future operation of the Riverside storage field.

A. The Riverside storage field has low working gas capacity, the largest well count compared to other Company gas storage fields with similar working gas volumes, and native hydrogen sulfide, which is flammable and lethal at high concentrations, that has caused it to be identified as high-risk within gas storage. 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 the ability to increase capacity at McBain City Gate. The integrity of the mainline and laterals that support the field are degrading, in some cases causing pressure derates. For these reasons, the Company has decided to end operation of the entire storage field.

Q. What type of engineering analysis and alternative analysis was performed to develop the Riverside retirement plan?

A. The engineering and gas supply team performed several models that included full field retirement, plugging and abandoning portions of the field, and optimizing the field with new horizontal wells. The evaluation also included determining gas withdrawal from the gas storage field. During the original analysis low gas price projections, along with the equipment necessary and timing of withdrawal, Consumers Energy determined that it would not be economical for the Company to spend capital to withdraw gas from the Riverside field. The Company modeled and evaluated several alternatives until a solution was determined. The selected solution must mitigate the current storage and transmission risk associated with the field, improve resiliency and reliability to customers connected to McBain, Forward, and Falmouth City Gates (customers that are currently being supplied through the storage field), continue to provide affordable gas in the Riverside area, and reduce methane emissions with the plugging of the storage wells.

In Case No. U-21308, the Company's gas rate case filed in 2022, MPSC Staff ("Staff") submitted testimony acknowledging the unfavorable economics of withdrawing the recoverable gas from the field but recommended that the Company continue to evaluate the potential sale of Riverside to a third party, who might be in a different economic position to produce the 8.6 Bcf of recoverable gas in the reservoir. The Company agreed to continue reviewing the sale of Riverside as an alternative to retiring and decommissioning the plant.

After gas prices increased in 2022, the Company revisited options for the withdrawal of gas from the field, including the option of selling the field to a third party. In late 2023, the Company identified a buyer and the parties have reached a purchase agreement. A closing date is tentatively planned for late 2025 to allow for the project work to remove customers from being fed by the storage field to be completed.

Q. What is the estimated timeline and projected cost for the Riverside projects and sale through the year 2026?

A. A breakdown of the projected spending for the Riverside project is included in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 18, the projected project spending does not include Cost of Removal. Distribution and Transmission asset modifications to disconnect customers from the storage field and re-supply from the system are planned for 2024 and 2025. Final closing on the sale of the field is planned to occur tentatively before the end of 2025. All projects will be closed out by 2026.

Q. Why is the sale of Riverside beneficial to customers?

A. The Company's estimated cost to retire and decommission Riverside is more than $24 million. This estimate includes the plugging of the remaining field wells and retirement of the mainline and laterals. These expenses will be avoided when the field is sold.

Although the sale of the plant is expected to result in a loss of approximately $9 million, the sale allows Consumers Energy to avoid the decommissioning costs, which creates a net benefit to customers. In Case No. U-21656, the Company sought Commission approval to record the expected loss from the Riverside sale as a regulatory asset for recovery in a future rate case. The Commission approved the Company's accounting request in Case No. U-21656 on July 23, 2024. Company witness Heather L. Rayl discusses the treatment of the regulatory asset in this case in her direct testimony.

Q. Please identify the capital expenditures projected for the Northville Storage Fields (Lyon 29, Lyon 34 and Northville Reef).

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 10, identifies the total capital expenditures for the Northville Storage Fields. In 2023, the Company incurred costs for its project to install a liquid handling system at the Lyon 29/34 storage fields. In 2024 through 2026, the projected costs include investment to complete the liquid handling system at the Lyon 29/34 storage fields and begin engineering/procurement on the Northville Reef Field liquid handling system. An itemized list of project costs used to create Exhibit A-12 (TKJ-5), Schedule B-5.7 is included in WP-TKJ-6. A breakdown of well rehabilitation work scope is included in Exhibit A-76 (TKJ-6).

Q. Please describe the Lyon 29/34 project.

A. The Lyon 29/34 storage gas gathering and metering site has been in operation for more than 22 years. The facility feeds gas to transmission Line 1020 and to the Northville compressor station. The primary focus of the Lyon 29/34 facility is to deliver transmission quality gas to the pipeline system and act as a metering station. On peak days, this site is an important additional source of natural gas supply to the metro Detroit area. During 2018, 2019, and 2020 there were multiple occasions of gas purity issues occurring during the gas withdrawal season. During gas withdrawal, the gas water content exceeded the regulatory threshold of 7 LB/MMCF, which affected the storage field, and required premature shut-in of withdrawal operations. The Lyon 29/34 facility upgrade project will help improve gas purity, measurement accuracy, and pipeline reliability by reducing corrosive components from the gas stream and improve site performance by installing gas purification equipment. In 2022, the expenditures were for project engineering and design. The 2023 expenditures were for concluding engineering, design and securing long lead time materials. The 2024 and 2025 expenditures are for securing remaining materials and performing construction, start up and project close out for the project. This project will help address the Company's objective of a reliable system, which will reduce unplanned outages during normal site operations.

Q. Was gas blending considered as an alternative to this project?

A. Yes. The Company does not consider blending a competent means of ensuring gas quality. Various conditions can affect how and whether gases are mixed in a pipe. Due to the integrated nature of Consumer 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 assume mixing occurs.

Q. Please identify the capital expenditures that are planned for the Overisel Storage Fields (Overisel and Salem).

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 11, identifies the total capital expenditures for the Overisel Storage Fields. In 2023, the Company incurred costs for disposal well tank replacements. In 2024 through 2026, projected costs include scrubber brine tank replacement and a Salem scrubber replacement. An itemized list of project costs used to create Exhibit A-12 (TKJ-5), Schedule B-5.7 is included in WP-TKJ-6. A breakdown of well rehabilitation work scope is included in Exhibit A-76 (TKJ-6).

Q. Please identify the capital expenditures projected for the Ray Storage Field.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 12, identifies the total capital expenditures for the Ray Storage Fields. In 2023 through 2026, the projected costs include valve replacements and a launcher receiver replacement. An itemized list of project costs used to create Exhibit A-12 (TKJ-5), Schedule B-5.7 is included in WP-TKJ-6. A breakdown of well rehabilitation work scope is included in Exhibit A-76 (TKJ-6).

Q. Please identify the capital expenditures projected for the St. Clair Storage Fields (Hessen, Puttygut, Four Corners, Swan Creek, Ira, and Lenox).

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 13, identifies the total capital expenditures for the St. Clair Storage Fields. In 2023 through 2026, examples of projected costs include completion of a disposal well facility upgrade and launcher/receiver replacement at Four Corners. An itemized list of project costs used to create Exhibit A-12 (TKJ-5), Schedule B-5.7 is included in WP-TKJ-6. A breakdown of well rehabilitation work scope is included in Exhibit A-76 (TKJ-6).

Q. Please identify the capital expenditures that are planned for Storage New Wells.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 14, identifies the total capital projected expenditures to complete the Company's new storage well drilling plan. In 2023, the Company incurred costs for the completion of drilling the two wells C-995 and C-996 in the Cranberry field, the re-entry of W-994 in the Winterfield field, and engineering and preparation for future well drilling and close out/flow testing after drilling. In 2024 through 2026, the projected capital expenditures include funding for the engineering, site preparation, and drilling of new wells. The table below outlines the timing and location of the Company's plan for drilling new wells.

Table 7: Proposed New Well Drilling Plan

Drill Year	Location	Field	New Well ID	Projected Cost
2023	Marion	Winterfield	W-994 (re-entry)	$3,338,861
	Marion	Cranberry	C-995	$6,300,178
	Marion	Cranberry	C-996	$5,251,591
2024	Overisel	Overisel	O-305	$9,759,300
	Marion	Cranberry	C-994	$6,563,713
2025	Marion	Winterfield	W-1004	$10,253,314
	Marion	Winterfield	W-1005	$7,728,750
	Marion	Winterfield	W-1006	$7,728,750
	Marion	Cranberry	C-1103	$10,641,316
2026	St. Clair	Puttygut	P-301	$8,237,405
	St. Clair	Puttygut	P-302	$6,852,403
	St. Clair	Four Corners	FC-201 (re-entry)	$3,537,775
	Ray	Ray	R-510	$9,571,623
	Ray	Ray	R-511	$7,102,411

Q. Please provide a description of the project at W-994 in the Winterfield Storage Field and FC-201 in the Four Corners Storage Field.

A. The projects are well re-entries focused on re-entering existing horizontal or deviated wells and drilling new horizontal drainhole sections. Re-entering an existing well further helps to improve field and well deliverability, especially for wells that were drilled off structure or too deep on the structure. The re-entry work is also expected to be significantly less expensive than a full new well as the casing, wellhead equipment and pipeline are already installed. There are eight wells in Winterfield, and one well in Lyon 34, that are potential future candidates pending the results of the W-994 and FC-201 projects.

Q. Please identify the capital expenditures that are planned for Well Rehabilitation.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 15, identifies the total capital projected expenditures for the Storage Well Rehabilitation Capital Program plus the wellhead protection and annular monitoring programs. Exhibit A-76 (TKJ-6), provides detail specific to the Storage Well Rehabilitation Capital Program, a multi-year program that is in response to the federal minimum safety standards that are described previously in my testimony.

Storage Well Rehabilitation Capital Project spending for 2024 through the end of the program was determined using estimates created based on work scopes developed by Storage Engineering. The work scopes are broken down into activities and costs and are developed using the projected duration of the activity using a vendor rate or on a cost-per-well basis, again based on a vendor quote. A description of the different work scopes and associated costs is shown on the Scope Averages tab of Exhibit A-76 (TKJ-6). The scope specific estimates were added together with the wells of similar scope types and averaged. This average was used to build the annual project expenses based on the number of each well scope performed each year. These costs are displayed on the Annual Estimate tabs of Exhibit A-76 (TKJ-6).

Q. Please provide more detail on the Well Rehabilitation Program.

A. The primary goal of the Well Rehabilitation Program is to identify and reduce well risk by ensuring the integrity of the wells across the Company’s gas storage system, preventing a large-scale methane emission event like Aliso Canyon. The secondary goal is to enhance well deliverability while working on the well. This program will initially provide a baseline of well integrity conditions, which will be incorporated into the ongoing development of the Storage Integrity Management Plan (“SIMP”). Development of the

SIMP is ongoing and the associated Risk Assessment Model is being used to identify well prioritization for the program. The completion of the logging portion will help complete a portion of the baseline assessment required from the PHSMA final rule.

This program will use mechanical methods, solvents, and other chemicals to remove obstructions, restoring the original flow properties of the wells. This thorough Well Rehabilitation Program will remove the debris and slow the rate of corrosion potential in the wells, thus increasing the useful life of the facilities.

Depending on the condition of the well, additional replacement of well components may be necessary. Components include, but are not limited to, piping, valves, or packers. To verify success of the Well Rehabilitation Program, flow statistics are taken both before and after the rehabilitation on select wells. Absolute Open Flow ("AOF") values are measured and compared to historical AOFs taken on the wells when originally put into service. Wells will be "logged" or inspected before treatment to assess the condition of the well casing and the success of the restoration. The program will bring the Company up to a seven-year reassessment cycle, into compliance with the API RP 1171, as part of the Storage system objectives as outlined in the NGDP.

Completing the rehabilitation and well logging work simultaneously is prudent, efficient, and directly benefits customers and public safety. If done separately, services such as well service rigs, well hardware, and other ancillary services would be duplicated, which is not cost effective for the customer. This program is designed to restore, and in most cases, increase well deliverability while baselining well integrity to an industry average of approximately 10 years. Once baseline well integrity information is determined, a risk-based, site specific approach to future well integrity well logging will be implemented as detailed in the API RP 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. At the completion of the well rehabilitation capital project, well logging O&M will be required to maintain the approximately seven-year cycle. The Company is 75% complete in its baseline risk assessment as of January 2024 with 747 wells completed. The Company plans to complete the baseline assessment in 2026.

Q. Why is the Well Rehabilitation Program a capital program?

A. Federal Energy Regulatory Commission ("FERC") Docket Nos. AC09-27-000 and AI05-1-000 illustrate FERC's allowance of testing costs incurred to extend the useful life of the system in the context of a one-time rehabilitation program to be capitalized. Under the requirement of FERC's Uniform System of Accounts, costs incurred to inspect, test, and report on the condition of an existing plant to determine the need for repairs or replacements, and testing the adequacy of repairs made, are recognized as maintenance expense. However, FERC has permitted natural gas and electric companies to capitalize assessment costs when the work was done in connection with major rehabilitation projects involving significant replacements and modifications of facilities.

FERC has established the following requirements that a project must meet to be able to capitalize assessment type costs. The project must: (i) be completed in connection with a one-time program that involves significant replacements and modifications of facilities; (ii) extend the overall system's useful life and serviceability; and (iii) have in place internal controls to distinguish between costs incurred related to ongoing assessment activities and those that are part of the rehabilitation project. The Well Rehabilitation Program meets these requirements.

Q. Please provide more detail on the annular monitoring program.

A. The annular pressure monitoring program allows for the well casing pressures to be measured, recorded and monitored as per the requirement in API RP 1171. The Company installed monitoring on 43 wells in 2023, 44 wells in 2024 and is projected to install 27 wells in 2025. All wells requiring annular pressure piping will be installed by the end of 2025. Annular pressure monitoring program average cost per well is approximately $15,000. The cost can reach $25,000-30,000 per well if a well plug is needed during the modification. Factors that impact this cost include but are not limited to soil type/condition, installation depth, welding requirements and pipe thickness/material.

Q. Please identify the capital expenditures that are planned for Storage Pipeline Replacement.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 16, identifies the total 2023 through 2026 capital projected expenditures for storage pipeline replacements. The projected pipeline replacement schedule is shown in Table 8, it includes the total projected cost of each project including both pipeline replacement and retirements. Retirement projects are provided for information only, they are entirely Cost of Removal/Retirement ("COR") expense and are not part of the request in this proceeding.

Q. Please provide more detail on the Storage Pipeline Replacement Program.

A. The Storage Pipeline Replacement Program is a program that performs replacement and retirement of storage pipelines to reduce the probability of major failure. All storage pipelines replacements and retirements will be tracked under the Transmission Integrity Management Program ("TIMP"), following 49 CFR 192 Subpart O, for risks and consequences of failures. Projects have been prioritized based on factors such as risk, future new well drilling, and planned well plugging. Replacement and retirement of these storage pipelines contribute to the safety of Company employees and the public, deliverability, resilience, and integrity of the Company's system.

Table 8: Projected Pipeline Replacement Schedule

Year	Location	Project Name	Project Type*	Projected Cost	Length (ft)	Act 9 Required	Anticipated File Date
2023	Marion	Cranberry Lateral 67E-Launcher/Receiver	Replacement	$815,072	53	No	N/A
2023	St. Clair	Puttygut Mainline	Replacement	$3,649,000	1,426	No	N/A
2024	Overisel	Overisel Lateral 2	Replacement	$8,899,720	5,095	No	N/A
2024	Marion	Cranberry Lateral 61W	Replacement	$4,620,000	1,785	No	N/A
2025	Overisel	Overisel Lateral 3	Replacement	$8,281,000	5,227	No	N/A
2025	Marion	Winterfield Lateral 52SB	Replacement	$4,446,000	1,056	No	N/A
2025	St. Clair	Hessen Full field	Replacement	$14,708,988	33,898	Yes	November 2024
2026	Overisel	Salem ML 2	Replacement	$3,752,000	4,013	No	N/A
2026	Overisel	Salem ML 3	Replacement	$2,942,000	2,800	No	N/A
2026	Overisel	Overisel ML -16"	Replacement	$12,675,000	13,707	No	N/A
2023	Marion	Cranberry Lateral 62W	Retirement	$1,645,798	9,768	No	N/A
2024	Overisel	Overisel ML - 10", ML – 12", Lateral 9, 8, 7E/W	Retirement	$5,594,252	42,451	No	N/A
2024	Marion	Cranberry Lateral 63W	Retirement	$420,000	1,486	No	N/A
2025	Overisel	Salem North Lobe Retirement	Retirement	$4,142,000	16,685	No	N/A
2025	Marion	Winterfield Lateral 56N	Retirement	$1,384,000	5,069	No	N/A
2025	Marion	Winterfield ML 22"	Retirement	$1,366,000	6,706	No	N/A
2026	Marion	Cranberry Lateral 64W	Retirement	$1,170,000	4,832	No	N/A
2026	Marion	Cranberry Lateral 66E	Retirement	$4,780,000	50,910	No	N/A
2026	Marion	Cranberry Laterals 67N/S	Retirement	$1,053,000	5,046	No	N/A

* Retirement projects are provided for information only; they are entirely COR expense and are not part of the request in this proceeding.

In previous years, the Company's Enhanced Infrastructure Replacement Program ("EIRP") has provided funding for the storage field lateral and mainline replacements, specifically for known higher-risk pipe within the storage fields. This includes pre-1970 Low Frequency Electric Resistance Welded ("LFERW") pipe. This pipe has been deemed higher relative risk pipe industry wide.

Starting in 2018, the Company ended the Transmission EIRP program and began this program to address the storage pipelines that do not qualify for EIRP funding. The well lines in the Overisel, Salem, Winterfield, Cranberry, and Riverside fields are original piping from initial field construction (Late 1940s and Early 1950s). Leaks have periodically developed on the well lines – average two to five per year across all of the fields. The condition of the well lines cannot be assessed with Inline Inspection tools since they are not piggable.

Q. Please identify the capital expenditures that are planned for Well Data Acquisition.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 17, identifies the total capital projected expenditures for well data acquisition. In 2023, the Company incurred costs for well data acquisition equipment installation and close out at the Ray Storage Field. In 2024 through 2026, project costs include funding for engineering, procurement, and installation of well data acquisition equipment on 24 wells in the Puttygut storage field and 24 wells in the Hessen storage field.

Q. Please provide more detail on the Well Data Acquisition.

A. PHMSA's adoption of API RP 1171 recommends increased monitoring of gas storage wells. In order to monitor flow, temperature, pressure, and other variables in real time, Remote Terminal Units and Supervisory Control and Data Acquisition (SCADA) systems need to be installed and equipped with sensing equipment at the well head. Along with complying with federal regulations, the ability to monitor issues on a well-by-well basis in real time during injection and withdrawal will provide valuable data to storage engineers that can be used to optimize the injection cycle and ensure deliverability from the field. The program plans to implement the technology in the peaker and intermediate fields, along with top performing and/or horizontal wells in the baseload fields. The benefits of a well SCADA system that can log the real time flow, temperature, and pressure will be well performance tracking, consistent annular pressure data and will allow the Company to utilize the data for future workover and maintenance activities.

Q. Please identify the capital expenditures that are planned for Safety Valve Installation.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 19, identifies the total capital projected expenditures for safety valve installation. Funding for safety valve installation projects began in 2024 with 4 wells at the Puttygut and Four Corners storage fields. The projected work scope in 2025 installs 22 safety valves at various well sites within the Puttygut, Hessen and Swan Creek fields and 5 safety valves in the Northville fields. Projected work scope in 2026 includes 6 safety valves installed in the Ira storage field.

Q. Please provide more detail on the Safety Valve Installation.

A. A SIMP integrity assessment (based on the regulatory requirements of API RP 1171 as referenced in 49 CFR 192.12) of surface equipment identified the need to standardize safety equipment on certain wells within higher deliverability fields. Protecting against a gas excursion from the individual well bore during any potential safety incidents.

Freedom Upgrade Project

Q. Please describe Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 1.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 1, identifies the total capital expenditures for the Freedom upgrade project.

Q. What level of capital spending does the Company propose for the Commission to incorporate into rates in this case for the upgrade project to Freedom?

A. The Company's request for rate relief in this case reflects capital spending on the upgrade project to Freedom in the amount of $8.4 million for 2023 (Actual); as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (b), line 1; $0.7 million for 2024 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (c), line 1; $0.0 million for the nine months ending on October 31, 2025 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (d), line 1; $0.7 million for the 21 months ending on October 31, 2025 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (e), line 1; and $0.0 million for the test year ending October 31, 2026 (Projected), as provided in Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, column (f), line 1.

Q. Please summarize the capital expenditures included in Exhibit A-12 (TKJ-5), Schedule B-5.7, included in this direct testimony for the Freedom upgrade project.

A. Exhibit A-12 (TKJ-5), Schedule B-5.7, page 2, line 1, identifies the total capital expenditures for the Freedom upgrade project. The Company has completed the construction and commissioning of the new equipment in the compressor and auxiliary buildings. In 2024, the Company is completing the site restoration and project close out.

Q. What is the annual investment for the overall Freedom upgrade project?

A. The annual investment for the Freedom upgrade project for the completed work and the work that is currently planned is shown in the table below. The projected amounts will continue to be evaluated as the project progresses and moves toward completion.

Anticipated Spend (Millions)	
2016	$16.8 (actual)
2017	$30.2 (actual)
2018	$62.3(actual)
2019	$83.0 (actual)
2020	$19.7 (actual)
2021	$13.8 (actual)
2022	$13.6 (actual)
2023	$8.4 (actual)
2024	$0.6 (projected)
2025	$0.0 (projected)
Total	$248.4 (projected)

Q. What is the state of Freedom Upgrade Project now?

A. Freedom has all five new compressor engines (18,750 BHP) permanently installed and commissioned in the new compressor building. Retirement and demolition of existing compressors and buildings has been completed. Site Restoration and Project close out is projected to be completed by the end of 2024.

Q. Are the Company's capital expenditures in GCS reasonable?

A. Yes. The capital expenditures in GCS will improve system reliability, deliverability, integrity, safety, and customer service. These capital expenditures will allow the Company to take advantage of market conditions and procure adequate supplies of natural gas to meet the needs of our customers. Furthermore, many of these capital expenditures are related to compliance with environmental, federal, and/or state regulations, and thus not discretionary.

(v) IT PROJECTS

Q. Is the Company planning technology projects that support the engineering, asset planning, design, construction, and maintenance of a safe, reliable, and affordable distribution, transmission, compression and storage systems for its customers?

A. Yes. Company witness Stacy H. Baker includes in her direct testimony and exhibits, technology projects that are critically important to supporting these gas functions within the Company. The expenditures for these projects are contained within her exhibits. The project which will provide benefits for the area which I am sponsoring is described below:

- The **Compression Air Permit and Compliance Digitalization** project requires $385,213 in capital and $38,105 in O&M in the test year.

  Description: This project modernizes and expands the use of software and digitized forms in support of station air permits and code compliance at Gas Compression facilities.

  Problem Statement: The current process around air permits and compliance for Gas Compression is cumbersome, largely paper based, and is made up of multiple disconnected systems. This leads to poor visibility, process inefficiency and waste, re-work, regulatory risk, and human error.

  Objectives: This project provides value to the Company through: (1) increased productivity by direct data entry in the field; (2) improved quality through increased accuracy of updates completed at the time and place of the work; (3) elimination of the need to enter data into multiple disconnected systems, and (4) improved safety through access to real-time information used at work sites rather than printed procedures and forms.

  Scope: The scope of the project includes: (1) Merging the existing air permit and compliance tools into a single solution, (2) purchasing licenses to add Gas Compression users to the company's existing mobile work management software, and (3) configuring changes in SAP and the mobile work management software to replace the paper-dependent process with the ability to access and update maintenance, operations, and safety information for Gas Compression.

The scope of the project includes: (1) purchasing additional software licenses to add Gas Compression users to the company's existing software solution, and (2) configuring changes in SAP and the mobile work management software to replace the paper-dependent forms and process with the ability to access and update maintenance, operations, and safety information at Gas Compression locations digitally.

Alternatives: Alternatives considered include: (1) Utilize an SAP work management mobile solution. An SAP work management solution was not selected since it is an unproven solution at the Company and would require additional project and support costs. (2) Continue with the manual paper-based processes and forms. Continuing with the manual paper-based processes and forms was not selected because it would not eliminate the identified process waste, re-work, and human error. (3) Customize the existing electronic Shift Operations Management System (eSOMS) mobile application to add work management functions. A customized mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the product was not intended to support. (4) Adopt a cloud based SAAS solution. This option was not selected as it was a high-cost option. (5) Utilize the existing Service Suite solution currently deployed for Gas and Electric Distribution. The Service Suite solution was selected because it is both an industry standard and a proven solution at the Company and provides the required mobility and digital benefits at a lower cost than other options.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

DIRECT TESTIMONY

OF

ASHLEY E. MESCHKE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Ashley E. Meschke and my business address is One Energy Plaza, Jackson, MI 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Lean Strategy

Q. Please review your educational and business experience.

A. I have a bachelor's degree in criminal justice with a specialization in Security Management from Michigan State University and a Master's in Infrastructure Planning and Management from the University of Washington. I have been employed with Consumers Energy since 2012 and I have been accountable for the improvement of performance metrics using lean methodologies in various organizations (gas, electric, and customer organizations) for the last eight years. I have also leveraged my expertise to improve several performance metrics associated with EICP during the last five years.

Q. What are your responsibilities as Director of Lean Strategy?

A. In the Director of Lean Strategy role, I am responsible for the development, governance, and administration of the operational metrics incorporated in the Company's Employee Incentive Compensation Plan ("EICP").

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for the test year EICP employee compensation costs related to operational goals. Specifically, I will discuss the operational goals included in Consumers Energy's EICP and how they provide customer-related benefits.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-95 (AEM-1)	2024 EICP Operational Goals;
Exhibit A-96 (AEM-2)	2024 Customer Benefits: Employee Safety;
Exhibit A-97 (AEM-3)	2024 Customer Benefits: Reliability; and,
Exhibit A-98 (AEM-4)	2024 Customer Benefits: Culture Index – Reduced Employee Turnover.

Q. Please explain the process for establishing the Company's EICP goals.

A. Each year, the Company identifies key operational and financial performance indicators to focus on for the next year. The EICP operational goals are key performance indicators that focus on continuous improvement across work and delivery processes resulting in improved outcomes and customer value. Achievement of these goals ties employee performance to improved utility performance and greater levels of customer benefit.

Q. What operational goals will make up the 2024 EICP portfolio?

A. The 2024 EICP operational goal portfolio is balanced to produce safe, reliable, and affordable service while ensuring that the Company is strategically positioned for its customers in the future. Successfully achieving goals in Employee Safety, Culture, Customer Experience, Electric Reliability, and Methane Emission Reduction will produce safe, reliable, and affordable service, and it will help to position the Company to be strong and sustainable in the future. Additional information regarding the 2024 portfolio of EICP goals is provided in Exhibit A-95 (AEM-1).

Q. Please explain the Employee Safety goal.

A. Employee Safety is measured through two metrics. First, reduction of Recordable Incident Rate (per the Occupational Safety and Health Administration ("OSHA") standard) is a guide to the number of injuries that may occur based upon the number of hours worked. Second, reduction of high-risk injuries ensures coworkers take proactive actions to reduce Company employees' exposure to high-risk injuries as part of Consumers Energy's Safety Culture improvement process. High-risk injuries (OSHA recordable and non-recordable) are defined in the Edison Electric Institute ("EEI") Safety Classification Learning Model as "High-Energy Serious Injury or Fatality (HSIF): Incident with a release of high energy in the absence of a direct control where a serious injury is sustained."

Q. Why is the Employee Safety goal included in the EICP?

A. Employee Safety is foundational to the success of the Company. Creating and maintaining a culture of safety allows the Company to serve customers safely and affordably while caring for co-workers. Economic benefits for customers are discussed later in my testimony.

Q. Please explain the Culture Index goal.

A. The Company uses an all-employee survey to determine the Culture Index which is made up of the indexes of (i) Engagement; (ii) Empowerment; and (iii) Diversity, Equity, and Inclusion. The Company's Engagement; Empowerment; and Diversity, Equity, and Inclusion indexes are how we measure culture values in action. The indexes focus on areas such as ensuring the Company has simple processes, fixes problems, and keeps the workforce engaged by measuring the combination of emotional commitment (how proud coworkers are to work here) and rational commitment (whether they plan to stay). The indexes also measure how well the Company embeds diversity, equity, and inclusion into everything it does through questions that ask whether coworkers feel like they belong at Consumers Energy and other questions described in Exhibit A-95 (AEM-1). Each of the three indexes is derived by averaging the favorability score from the responses regarding five questions per index, of the Company's employee engagement surveys. Korn Ferry administers the survey using Qualtrics as the survey platform.

Q. Why is the Culture Index goal included in the EICP?

A. The Culture Index goal focuses on improving the employee experience and engagement in their work. Companies that experience high employee engagement have 10% higher customer loyalty and engagement and 18% more productivity than companies with low engagement as detailed in Gallup's most recent meta-analysis on engagement, covering more than 112,000 teams, in 276 organizations, across 54 industries, and in 96 countries.[1] Improving Culture will reduce employee turnover and improve the Company's ability to affordably serve customers. Benchmark data shows that peer utilities experience turnover at a rate of 7.3%, while the four-year historical average for the Company has been 3.3%. Unsurprisingly, retention and engagement are correlated. Companies with first-quartile employee engagement experience 43% less turnover and 18% lower absenteeism. While the Company's retention rate is higher than peers, its turnover rate among co-workers who have been with the Company for four years or less does trend higher than the average rate at a four-year historical average of 4.2%. The cost of turnover is high, with estimates that the turnover of an employee can cost a company 1.5-2.0 times the existing employee's salary as the organization experiences additional recruitment activities and lost productivity. For purposes of quantifying customer benefits, I will utilize the lower end of this range, 1.5 times the existing employee's salary. Of the Company's coworker base, 2,581 have four or less years with the Company. Creating and building upon an employee

[1] https://www.gallup.com/workplace/285674/improve-employee-engagement-workplace.aspx#ite-285704)

experience that fosters improved retention within that work group enables the Company to provide better service to customers and avoid unnecessary costs. Through the Company's Culture Index goal, a focus on improving culture will lead to retention of shorter tenured Company employees. With a continuously improving culture, Consumers Energy is able to achieve and maintain a minimum of a 2% advantage over its peers' total experience within this four years or less tenured population of co-workers. By creating and maintaining this competitive advantage over peer utilities, the Company avoids costs of at least $7.4 million annually.

Q. Please explain the Customer Experience Index goal.

A. Customer Experience Index is a survey administered by Forrester[2] and is a measure of customer service based on three questions: Did we meet your needs? Was it easy to do business with us? Was the experience enjoyable? The metric is calculated by asking those three questions of customers on a scale of 1 to 5 with 4s and 5s being positive responses, 1s and 2s being negative responses, and 3s being a neutral response. To calculate the score, the number of negative responses is subtracted by the number of positive responses, which is then divided by the total number of customers responding. The results of the three questions are averaged together to calculate the Customer Experience Index score.

Q. Why is the Customer Experience Index goal included in EICP?

A. The Customer Experience Index goal focuses on ensuring that when customers contact Consumers Energy, customer needs are met, the interaction is easy for the customer, and the experience is enjoyable for the customer. This results in enhanced productivity (e.g. reducing the number and duration of customer calls, which benefits the Company and

[2] https://go.forrester.com/analytics/

the customer) and customer value (e.g. quick, easy, and enjoyable solutions for customer experiences).

Q. Please explain the Electric Reliability goal.

A. The Company uses the industry standard for Customer Outage Minutes, or System Average Interruption Duration Index ("SAIDI"), as a measure of electric distribution reliability. Electric Reliability/SAIDI is a utility-industry benchmark; SAIDI measures the total time an average customer experiences a non-momentary power interruption in a one-year period.

Q. Why is the Electric Reliability goal included in EICP?

A. The Company is committed to providing Customers with safe, reliable, and affordable service. Improving electric reliability provides an economic benefit to customers and strategically positions the Company to be successful in the future. Economic benefits for customers are discussed later in my testimony.

Q. Please explain the Methane Emissions Reduction goal.

A. This goal tracks the reduction in fugitive methane emissions associated with the Company's natural gas distribution system. Reductions are obtained as a result of the following activities: (1) retiring and replacing miles of natural gas distribution mains, (2) retiring and replacing natural gas distribution services (both vintage and non-vintage materials), (3) natural gas distribution system leak replacements, (4) well plug and abandonment activities, and (5) reducing compression venting. Work groups performing these activities include Natural Gas Construction, Natural Gas Distribution, and Contractors. These activities are further outlined in the Company's Natural Gas Delivery Plan, Exhibit A-42 (NPD-1).

Q. Why is the Methane Emission Reduction goal included in EICP?

A. The Company is committed to providing Customers with safe, reliable, and affordable service. In 2020, Michigan's Governor signed an executive order creating the Michigan Healthy Climate plan, which outlines goals for Michigan to achieve economy-wide net-zero greenhouse gas emissions and to be carbon neutral by 2050. The executive order aims for a 28% reduction below 2005 levels of greenhouse gas emissions by 2025. This goal supports the federal government's goal of net-zero emissions economy-wide by 2050 as well as the Paris Agreement. In addition to supporting these goals through the Company's Clean Energy Plan, it is important to address greenhouse gas emissions from the natural gas portion of the business as well. The largest constituent of natural gas is methane, which is a greenhouse gas 25 times more potent than carbon dioxide, and reducing those emissions is a key component to combating climate change. As a result, the Company has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. The Company plans to reduce methane emission from its system by about 80% by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will be offset by purchases and/or producing renewable natural gas. By achieving this goal, the Company will reduce its methane emissions by more than 10,000 metric tons — that's the equivalent of removing about 55,000 vehicles from the road for a year or preserving more than 300,000 acres of forest. Reducing those emissions will support limiting global emission increases which have been attributed to increased storm activity globally as well as here in Michigan. Consumers Energy is committed to caring for people, protecting the planet and empowering Michigan's prosperity. The achievement of this goal ensures that the Company will be able to serve its customers safely, reliably, and affordably for many years.

Q. Please explain the goal target setting process.

A. Alignment of goal targets with strategic plans is developed by subject matter experts and recommendations for annual targets are provided to the Company leadership team. The leadership team evaluates the recommendations and ensures that there is a focus on continuous improvement and customer value. Targets are established to set clear expectations of continuous performance improvements that are challenging but achievable goals. Operational targets are approved annually by the Board of Directors.

Q. Has the Company quantified customer benefits that are tied to its EICP?

A. Yes. Although specific quantification of the benefits is not easy to perform for every metric included in the program, the Company has evaluated direct quantitative benefits of three key metrics of the program: Employee Safety, Electric Reliability, and Culture. And the Company has assessed indirect and/or qualitative benefits associated with the other metrics.

Q. Is there a direct tie between the design of the EICP operational goals and desirable benefits for customers?

A. Yes. There is a direct tie between the design of the EICP operational goals and desirable benefits for customers. The operational goals focus on safety, reliability, and customer value, which are all desirable benefits for customers.

Q. Do you believe that benefits to customers from the EICP goals will, at a minimum, be commensurate with the programs' costs?

A. Yes. Company witness Amy M. Conrad and I present evidence in support of including EICP costs at the 100% payout level proving that including these costs will not result in excessive rates and that the costs of the EICP will, at a minimum, be commensurate with the programs' costs. Company witness Conrad discusses various benefits to customers from the design of the Company's EICP. In addition, there are both quantitative and qualitative benefits to the successful achievement of these goals. The design of the EICP clearly leads to lower costs and improved service which benefit customers.

Q. How have you evaluated the EICP goals' direct quantitative benefits?

A. The direct quantitative benefits associated with Employee Safety, Electric Reliability, and Culture Index have been calculated. For each of these metrics the Company uses a four-year historical average baseline. The first of those metrics is Employee Safety. The Employee Safety goal for 2024, when met, will reduce incidents by 29% from the four-year historical average. The resulting reduction in lost workdays and medical expenses approximates $968,000 of annual direct savings. Expected indirect savings, calculated using OSHA's recommended multiplier, total $656,000. Together, the projected annual direct and indirect savings that accrue to the benefit of the customer total $1.6 million. Exhibit A-96 (AEM-2) provides the calculation of these savings. The second metric that can be readily translated to quantifiable cost avoidance for customers is in electric distribution reliability. Using cost per outage minute estimates from Berkeley Labs,[3] the 5.0-minute average annual reduction in outage minutes from the 2020-2023 historical

[3] https://www.osti.gov/servlets/purl/963320

baseline to the 2024 Electric Reliability goal of 170 minutes results in annual economic benefits to customers in excess of $15.4 million. Exhibit A-97 (AEM-3). Third, there are benefits related to the Culture Index created by reducing employee turnover for Company employees with <1-4 years of tenure by 2% as compared with industry peers. The average annual salary of an employee with tenure of <1-4 years experience is $95,346. And, as discussed above, lower turnover avoids costs equal to at least 1.5 times the employees' annual salaries. This means that by reducing turnover in this employee group by 2%, when compared to utility peers, the Company will avoid costs of $7.4 million. Exhibit A-98 (AEM-4) shows the calculation in further detail.

Q. How have you evaluated the EICP goals' other qualitative benefits?

A. Methane Emission Reduction is essential to achieving the Company's goal of net-zero methane emissions from its natural gas delivery system by 2030, which supports the Michigan Governor's goal for Michigan to achieve economy-wide net-zero greenhouse gas emissions and to be carbon neutral by 2050. The direct economic benefits for customers are difficult to calculate, but the qualitative benefits are beyond dispute. Improved Customer Experience is another benefit of achieving EICP goals that is difficult to quantify but nonetheless quite real. The benefits of pursuing improvement in Customer Experience have been discussed above.

Q. Why have you included both electric and natural gas benefits in your quantification?

A. Consumers Energy's utility operations are combined in one organization. Establishing operational goals in the critical areas of safety, reliability, customer value, and employee culture helps keep employees focused on the importance of continuous improvements in these priority areas for both the electric and natural gas operations. The quantified benefits of Employee Safety and Employee Culture show that benefits to natural gas customers clearly exceed the employee incentive compensation amounts that Consumers Energy has requested to be included in rates in this case. The EICP metrics are based on annual targets that support the achievement of Consumers Energy's continuous improvement goals that significantly benefit the customers.

Q. What portion of the direct benefits that you have quantified above do you conclude benefit natural gas customers?

A. A portion of the quantified benefits in the area of Employee Safety and avoided costs associated with Culture Index benefit natural gas customers. Utilizing an allocation of 40% for natural gas customers, this equates to annual savings for natural gas customers of $640,000 for Employee Safety, plus the cost avoidance benefit of improved employee retention of $2,960,000 totals $3,600,000, far exceeding the total costs of the EICP allocated to natural gas customers.

Q. Why did you use a 40% allocation to evaluate benefits to natural gas customers?

A. The 40% allocation is based on the total number of natural gas employees as a percentage of total number of Consumers Energy employees. Using the percentage of total employees is a reasonable allocation methodology to allocate the Employee Safety and Culture Index benefits identified above.

Q. Should the Company be pursuing these benefits independent of the EICP?

A. Yes. The EICP takes this into consideration. As discussed by Ms. Conrad in her direct testimony, incentive mechanisms help communicate priorities, engage employees in business success, reward valued skills and behaviors, and create business understanding for employees. The EICP is structured in a way that focuses employees on enhancing customer value through continuous improvement outcomes. Making it clear to employees that a portion of their market-based compensation is at risk and depends upon their collective ability to meet these targets emphasizes the importance of improving customer value and encourages coworkers to deliver their best performance.

Q. Do you believe that the EICP is the reason that the above benefits have been realized?

A. Yes. I believe that the design of the EICP is intended to, and does, make it significantly more likely that these customer benefits will be achieved through the improvement in the areas of focus identified by the EICP goals. By placing a portion of employees' market-based compensation at-risk, they are incentivized to deliver on the EICP goals related to safety, reliability, and employee culture.

Q. Do you believe that any of the metrics included in the EICP are duplicative?

A. No. The metrics have been selected to create a designed, balanced focus on safety, reliability, and employee culture that results in broad customer benefits.

Q. Does this conclude your direct testimony?

A. Yes.

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 for other relief.	)))))	Case No. U-21806

DIRECT TESTIMONY

OF

KRISTINE A. PASCARELLO

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Kristine A. Pascarello, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your current position with Consumers Energy?

A. I am a Senior Strategy Manager in the Gas Strategy department within Gas Engineering and Supply. I have held this position since July 2019.

Q. What are your responsibilities as Senior Strategy Manager?

A. I perform the asset lifecycle oversight, guidance, and leadership of the Natural Gas Delivery Plan ("NGDP") development, implementation, recovery, and verification of results focused on the Distribution assets.

Q. What other relevant experience do you have?

A. I have worked for Consumers Energy for 25 years. I have been a Senior Strategy Manager in Gas Engineering and Supply since 2019. I have also served the Company as a Project Manager, Deployment Lead, Senior Engineer Lead, and Engineer. Prior to becoming a Senior Strategy Manager, I spent 10 years on the Smart Energy Advanced Metering Infrastructure ("AMI") and Gas Automated Meter Reading ("AMR") project teams where I was responsible for leading field implementation activities required to install electric smart meters and gas communication modules. This involved business process redesign and system requirements definition, working with a wide variety of stakeholders including customers, municipalities, and various Company departments such as Field Operations, Supply Chain, Customer Contact Center, Rates, Damage Claims, and Security, and successfully implementing new technology while delivering a high-quality customer experience. I was also the contract administrator and Company supervisor for the meter installation vendor. Before joining the AMI/AMR projects, I was in the Gas Engineering department. I was the Gas Measurement Lead for 2.5 years, the Electrical, Instrumentation, and Controls ("EI&C") Lead for 5 years, and a General/Senior Engineer for 2.5 years. As the Gas Measurement Lead, I led the Measurement Center of Excellence, was responsible for Lost and Unaccounted for Gas ("LAUF") projects including the development of standardized gas measurement processes, and the monitoring of LAUF, including implementation of Flow-Cal gas measurement software. During my 7.5 years as the EI&C Lead/Engineer, I was responsible for project management and electrical design of the Company's natural gas facilities, including managing the Gas Transmission and Distribution Supervisory Control and Data Acquisition ("SCADA") system designs and installations. Prior to joining Consumers Energy, I worked as an Electrical Engineer at Dart Container for four years where I was responsible for machine control design, including PLC programming and variable frequency drives. I started my career as an Electrical Engineer at Florida United Engineers, where I was a contract Electrical Engineer for Florida Power & Light specializing in generation power distribution processes and power plant control/alarm designs for seven years. I have a total of 36 years of experience, with 32 years in the utility industry.

Q. Are you a member of any professional societies or trade associations?

A. Yes. I am currently a member of the Engineering Society of Detroit. I am also a certified Project Manager through the Project Management Institute ("PMI"). I have represented the Company at the American Gas Association ("AGA") where I served as a Distribution

Measurement Committee ("DMC") officer, chaired the AMI/AMR subcommittee, and delivered presentations during conferences. I have also served on the American National Standards Institute ("ANSI") B109 working committee.

Q. What is your formal educational experience?

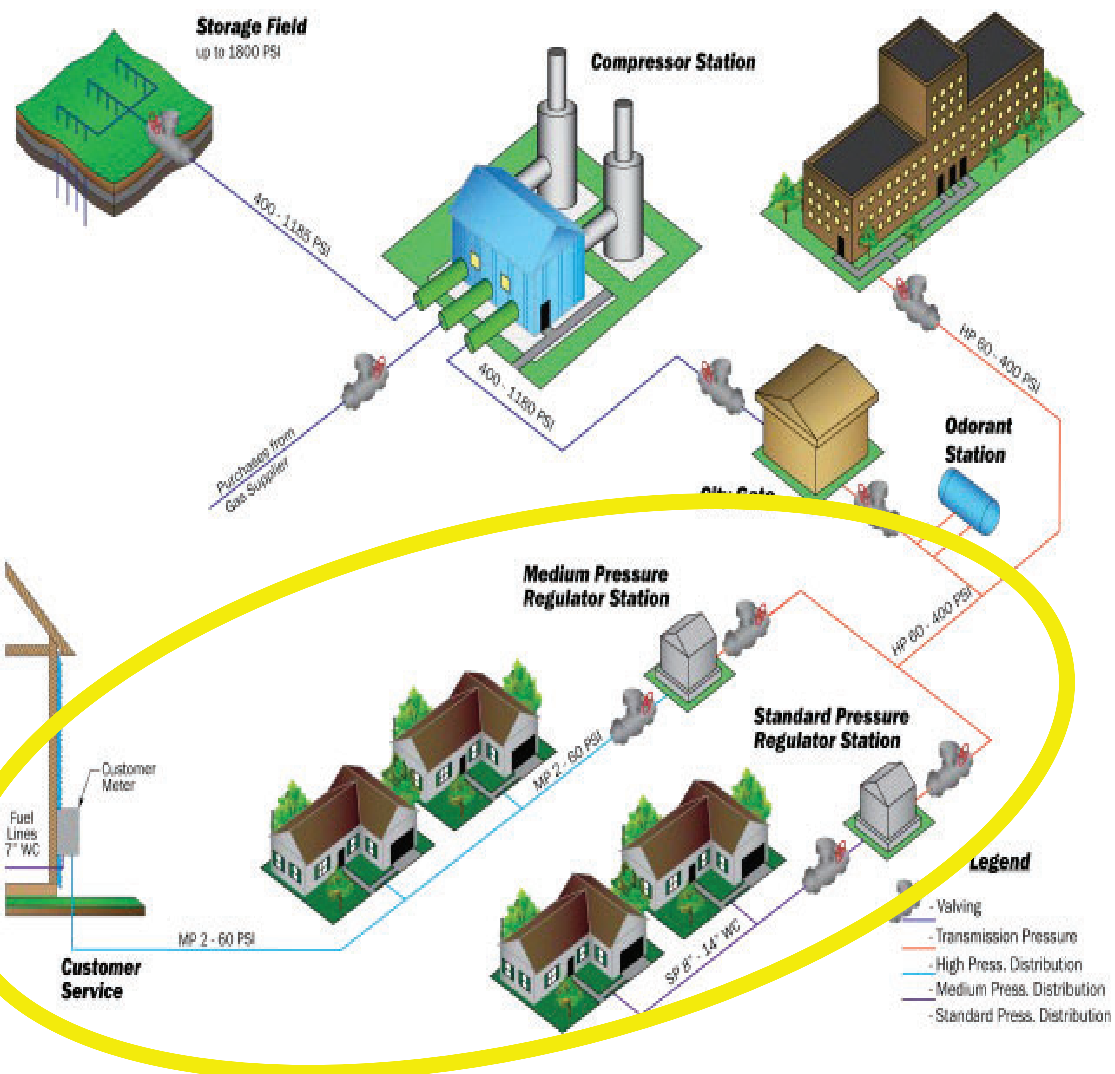
A. I graduated from Lake Superior State University with a Bachelor of Science degree in Electrical Engineering Technology. I graduated with an Associate of Science degree in Electronics from Lansing Community College. I also hold Master and Associate Certificates in Project Management from George Washington University, and Gas Measurement Fundamentals Certification from the Gas Certification Institute. In addition, I passed the Fundamentals of Engineering exam in 2004.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I testified in Case Nos. U-20893, U-21148, U-21308, and U-21490.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to explain the Company's request for rate relief as it relates to Gas Engineering and Supply ("GE&S") Operating and Maintenance ("O&M") expenses, and certain gas distribution capital investments that are intended to keep the system safe and reliable while providing affordable and clean energy to customers. The Company's sustainable and equitable approach to gas distribution investment benefits all customers, including our more vulnerable populations, with cleaner and safer infrastructure. This includes engineering, strategy, and gas supply for this system as well as gas control of the transmission system. The distribution assets are the portion of the Company system that receives the gas at the outlet of the Company's city gates and delivers the gas to customers, a portion of which is monitored by Gas Control. In the diagram below, these assets are inside the yellow highlighted section.



These expenditures are primarily related to the operation of the Company's gas mains, services, and meters downstream of the city gates. These investments will ensure the continued safe delivery of gas through this system to customers.

I have divided my direct testimony into two parts: (i) a description of the O&M expenses related to the Company's GE&S department; and (ii) a description of the Company's gas distribution capital expenditures that I am sponsoring for 2023, 2024, the

10 months ending October 31, 2025, and for the projected test year 12 months ending October 31, 2026. My direct testimony covers the capital cost for the Material Condition and Gas Operations Other programs. The remaining capital programs for Distribution are sponsored by Company witness Lincoln D. Warriner.

Q. How does your direct testimony relate to the NGDP presented by Company witness Neal P. Dreisig?

A. Mr. Dreisig's direct testimony discusses the Company's NGDP. My direct testimony contains elements that support the objectives of the NGDP: providing gas supply that is safe, reliable, affordable, and clean. The GE&S department is responsible for the engineering, design, strategy, project management, construction support, and gas supply and control associated with execution of the NGDP. The distribution capital programs represented in my direct testimony work toward achieving the NGDP's objectives of eliminating vintage materials and leaks, as well as providing safe and reliable service.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-80 (KAP-1)		Summary of Actual & Projected O&M Expenses, Gas Engineering and Supply;
Exhibit A-81 (KAP-2)		Detailed Summary of Actual & Projected O&M Expenses, Gas Engineering and Supply;
Exhibit A-12 (KAP-3)	Schedule B-5.8	Projected Capital Expenditures, Distribution Plant – Material Condition and Gas Operations Other, Summary of Actual & Projected Gas and Common Capital Expenditures;

Exhibit A-82 (KAP-4)	Actual & Projected Gas Capital Expenditures - Material Condition Program;
Exhibit A-83 (KAP-5)	Actual & Projected Gas & Common Capital Expenditures - Gas Operations Other Program;
Exhibit A-84 (KAP-6)	Detailed Summary of Actual and Projected Capital Expenses – Enhanced Infrastructure Replacement Program;
Exhibit A-85 (KAP-7)	Projected Capital Expenditures - Distribution Plant - Material Condition and Gas Operations Other, Summary of Actual & Projected Gas and Common Capital Expenditures.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. Please summarize your direct testimony.

A. First, I will address the reasonable and necessary O&M expenses for the Company's GE&S department, which are described on Exhibit A-80 (KAP-1). The total O&M expenses were $16,014,000 in 2023; and are projected to be $20,694,000 for 2024; $22,530,000 for 2025; and $22,195,000 for the test year 12 months ending October 31, 2026, as set forth on this exhibit on line 5, columns (b) through (e).

Second, my direct testimony also represents certain Gas Distribution capital investments through October 31, 2026, which are described on Exhibit A-12 (KAP-3), Schedule B-5.8. The total Gas Distribution capital expenditures represented by this direct testimony were $274,046,000 in 2023 and are projected to be $301,775,000 for 2024; $313,809,000 for the 10 months ending October 31, 2025; and $402,755,000 for the projected test year 12 months ending October 31, 2026; as set forth on this exhibit on line 3, columns (b), (c), (d), and (f), respectively.

Q. Were there any organization changes impacting GE&S for this case?

A. Yes. Company reorganizations in 2024 have restructured certain departments to better align with strategic goals. The following changes occurred in 2024.

- Effective May 1, 2024, the Company reorganized the Quality Lean office to enhance collaboration, alignment, and accelerate the maturity of the CE Way. This reorganization resulted in the formation of three teams within the Quality Lean Office: Design and Strategy, Industrial Engineering, and the Quality Improvement Center of Excellence. A total of 63 co-workers were impacted by this change, with 31 of them being assigned to the Gas Quality Lean team.

- Effective May 31, 2024, the Gas Compression & Storage technicians transitioned from Gas Compression Operations to the GE&S Gas Engineering - Transmission department joining the Measurement, Regulation and Controls ("MR&C") team. The 2023 historical and 2024 January through May O&M expenses of $346,131 and $129,292, respectively, for the Gas Compression & Storage technicians are included in Company Witness Timothy K. Joyce's Exhibit-72 (TKJ-1), line 1. The projected June through December 2024 expense of $196,544 and projected future O&M expenses are included within the Gas Engineering - Transmission expenses shown on Exhibit-81 (KAP-2), line 3.

- Effective August 1, 2024, the Enterprise Corrective Action Program ("ECAP") department was moved into the Quality Lean Office. The historical 2023 O&M expenses for this department were $207,865 and are split between GE&S ($53,555) and Gas Operations ($154,310) due to the 2023 reorganization described later in this testimony. The 2024 projected O&M expenses for the ECAP department are $116,133 and are included within Exhibit-81 (KAP-2) with the January through July 2024 O&M expenses of $64,461 represented in line 13. The August through December 2024 O&M expenses of $51,672 and projected future O&M expenses are included in the Project Management and Quality Lean Office expenses shown on line 1.

- Effective August 1, 2024, the Operational Technology ("OT") Gas SCADA team responsible for gas SCADA development, including operations and 24/7 support, transitioned to Gas Management Services joining the Gas Control team from the IT&S-OT Critical Applications team. This change will streamline the interface between Gas SCADA and 24/7 gas control operational needs and improve support of construction activities. The 2023 historical and January through July 2024 O&M expenses of $68,992 and $31,948, respectively for the OT Gas SCADA team are included in Company Witness Stacy H. Baker's Exhibit-17 (SHB-1), line 1. The projected O&M expense of $24,000 for August through December 2024 and projected future O&M expenses are included in the Gas Management Services expenses on Exhibit-81 (KAP-2), line 15.

Q. How has the Company projected its O&M expenses for 2024, 2025, and the test year 12 months ending October 31, 2026?

A. The Company has projected its O&M expenses to meet customer service and safety requirements. This projection considers several factors, including annual merit increases for the GE&S department, Company reorganizations, and specific program expenses necessary to ensure customer safety, meet regulatory requirements, and provide reliable service to customers. The Company started with the historic 2023 O&M expenses, which include GE&S personnel assigned to the department for the full year. In 2023, a reorganization of the Gas Operations Compliance and Controls ("OCC") department added new personnel to the GE&S department. However, these new staff members are only partially included in the GE&S historic expenses. As part of the 2023 Company reorganization, the Damage Claims/Prevention, ECAP, and Advanced Methane Detection ("AMD") personnel were added to GE&S. Due to this reorganization, the January through August 2023 historical O&M expenses for these departments are included in Company witness James P. Pnacek's Exhibit A-89 (JPP-4), page 3, line 1, Compliance and Controls and the September through December 2023 expenses are included in Exhibit A-81 (KAP-2). To project the O&M expenses accurately, the full-year salaries and expenses for the new staff members added during the reorganization were used to account for the full-year impact of the additional staffing from the reorganization. The Company then applied merit increases to labor, keeping non-labor expenses flat unless specific new expenses, such as software licensing, were added, to the historic 2023 O&M expenses. The projected expenses reflect the full-year costs of the reorganized staffing levels, ensuring a comprehensive projection for 2024, 2025, and the test year ending October 31, 2026. The test year projections are included in Exhibit A-81 (KAP-2). Lastly, the projection methodologies vary among the different O&M programs and are described within each respective section later in this direct testimony.

Q. Please describe the methodology used to project the Company's Gas Distribution capital expenditures for the years 2024 through the 12 months ending October 31, 2026.

A. The projected capital expenditures for this period are based on projected costs for individual projects and programs, using historical costs and adjusting for market conditions impacting areas such as materials and outside services, necessary to ensure customer safety, meet regulatory requirements, and provide reliable service to customers. The projection methodology is based on the monthly cash flow average percentage, using the three-year historical period of 2021 through 2023.

<u>**GAS ENGINEERING AND SUPPLY DEPARTMENT O&M EXPENSES**</u>

Q. Please explain the source of the 2023 actual O&M expenses for the GE&S department expenses shown on Exhibit A-80 (KAP-1), line 5.

A. The 2023 actual O&M expense amount of $16,014,000 for the GE&S department was taken from Consumers Energy's internal reporting records. This total amount includes both labor and non-labor O&M expenses for this department, and the labor, material, contractor, non-labor overheads, and other non-labor expenses are detailed on Exhibit A-81 (KAP-2), pages 1 through 4. The 2023 level of expense allowed the Company to provide the engineering and support needed to serve 1.8 million natural gas customers and complete reasonable and necessary investments in 2023. The projected expenses for 2024 are $20,694,000; for 2025 are $22,530,000; and for the test year 12 months ending

October 31, 2026, are $22,195,000 as shown on Exhibit A-80 (KAP-1), line 5, columns (c), (d), and (e), respectively. The calculation of expenses in the test year of this case is further described below.

Q. Please explain the derivation of the GE&S department O&M expenses for the test year as shown on Exhibit A-80 (KAP-1), line 5, column (e).

A. First, the Company has projected expenses for engineering and supply personnel, including departmental changes resulting from Company reorganizations described earlier in my testimony, to implement the investment in the gas system replacement as described in the NGDP. These changes result in a net increase of 27 GE&S staff members for 2024, with the total staffing levels for 2023, 2024, 2025, 2026, and the test year ending October 31, 2026, being 588, 615, 615, 615, and 615, respectively. Each department within GE&S analyzed the work activities and factored in productivity improvements to determine the necessary number of employees. The analysis helps determine the appropriate percentage of capital and O&M expenses for each department. The O&M percentage for each department is applied to the total department projected expenses to derive the O&M portion shown in Exhibit A-80 (KAP-1) and detailed in Exhibit A-81 (KAP-2). This staff will be responsible for engineering planning, engineering design, permitting, and construction support for the gas system enhancements as well as gas compliance, geospatial management, strategy, damage claims/prevention, enterprise corrective action, gas control, supply, transport and customer choice, and system and operations planning.

Second, the Company also has projected O&M expenses for the Storage Integrity Management Program ("SIMP"), the AMD Program, and the Geospatial Inventory and

Modeling Program. The details of these programs and the associated O&M expenses are described later in this testimony.

The resulting projected costs for the 12 months ending October 31, 2026 are $22,195,000, and can be found on Exhibit A-81 (KAP-2), page 4, line 16, column (e). These expense levels for the GE&S department will allow the Company to meet customer service, deliverability, and safety requirements in the test year.

Q. Are there any Employee Incentive Compensation Program ("EICP") O&M expense dollars included in your exhibits?

A. No, there are not. The direct testimony and exhibits of Company witness Amy M. Conrad contain the EICP O&M expense dollars.

Q. Please briefly describe each of the departments within GE&S, as listed on Exhibit A-81 (KAP-2).

A. GE&S is described in four major departments:

- Gas Project Management and Quality Lean Office;
- Gas Asset Management – Consists of Gas Engineering - Distribution, Gas Engineering – Transmission, Gas Engineering Asset Planning, System Integrity, which includes SIMP, and Gas Compression Engineering;
- Gas Engineering Support – Consists of Gas Strategy, Gas Regulatory and Compliance, which includes the AMD Program, Geospatial Management and Data Quality, which includes the Geospatial Inventory and Modeling Program, Damage Claims/Prevention, and Engineering Management; and
- Gas Management Services.

Q. Please briefly describe pages 5 through 7 of Exhibit A-81 (KAP-2).

A. Pages 5 through 7 of Exhibit A-81 (KAP-2) is provided to present the amounts of the O&M expenses I am sponsoring. Column (b) shows the historical O&M expense and column (j) is the projected test year O&M expense. Column (i) represents the increase (or decrease) in O&M expenses. The expenses that I am supporting are based upon the expenses necessary to comply with regulations and improve system safety as described for the programs below and have not been projected utilizing inflation factors.

Q. Please describe the activities of the Gas Project Management and Quality Lean departments.

A. Gas Project Management provides project oversight and management for certain programs and projects that are required by the business or directly for a customer. These programs and projects are usually large or complex in nature and require project management methodology to ensure predictable results. The Gas Project Management team includes Company-employed and contract project managers who oversee projects and ensure that each project meets the intended scope, schedule, and cost projection.

The Quality Lean department is responsible for the Company's quality management system. This department establishes and maintains standards, processes, procedures, and policies that ensure both Company and regulatory requirements are consistently met. Key responsibilities include developing and implementing standards, processes, procedures, and policies, supporting overall business efficiency by reducing waste and errors, and enhancing customer satisfaction by addressing potential or identified non-conformances. This department facilitates activities involved in evaluating and improving enterprise-wide processes through Value Stream Assessments. These assessments help identify continuous improvement opportunities, which are then addressed using the CE Way Lean Toolbox. In August 2024, the ECAP was integrated into the Quality Lean organization. Initiated at Consumers Energy in 2020, ECAP is an enterprise-wide issue management and compliance program designed to support safe and excellent operations. The structured platform and methodology allow for transparency in reporting issues, identifying trends, and closing compliance and safety gaps through corrective actions and controls, based upon associated risk thresholds. ECAP's functionality for managing processes and performance, as well as analyzing data, focuses risk reduction efforts, informs operational business decisions, and promotes the integrity and deliverability of the energy infrastructure. Starting in 2022, ECAP supported stakeholders in Gas Operations and Engineering to maintain adherence to GSMS standards established in American Petroleum Institute Recommended Practice ("API RP") 1173. ECAP is responsible for the management of an integrated safety assurance approach to proactively sustain and assess the needs of the Company's operational compliance performance. The program implements a common process and technology that fully integrates corrective and preventative action ("CAPA") management. CAPA is a fundamental tool in the Company's quality management systems to support the elimination or prevention of non-conformances and that process is supported by a strong problem-solving structure. This organizational change will enable continued strengthening in the use of the CE Way and bring together the quality management platform which is the Company's system of record for documenting potential or identified non-conformances.

The projected O&M expenses for Gas Project Management is $1,132,000 and the Quality Lean department is $2,020,000 for the 12 months ending October 31, 2026, totaling $3,152,000, as shown on Exhibit A-81 (KAP-2), page 1, line 1, and consists of the O&M portion of the salaries and expenses for project managers, performance managers, and their Company-employed and contracted support staff. The increase from 2023 historic year is due to the 2024 Company reorganizations of the Quality Lean department in May and the

ECAP team in August as described earlier in my testimony. The support staff for Gas Project Management ensures project schedules are produced, tracks project expenses, provides construction oversight and inspection, and ensures appropriate resources are available for the project. The Quality Lean staff ensures quality management implementation in planning and execution of work.

Q. What operating sections are included in the Gas Asset Management department?

A. The Gas Asset Management department consists of all engineering and technical support for planning, designing, performing risk assessment, and construction support of the transmission mainlines, distribution mains, storage laterals and wells, service lines, meter installations, regulating stations, compressor stations, and other infrastructure involved in delivering natural gas to customers safely and reliably. Gas Asset Management consists of five sub departments that I will describe more fully below. They are:

- Gas Engineering – Distribution;
- Gas Engineering – Transmission;
- Gas Engineering Asset Planning;
- System Integrity; and
- Gas Compression Engineering.

The employees within Gas Asset Management provide gas engineering and asset planning for the compression, storage, transmission, and distribution pipelines, large metering, regulation, and measurement assets, along with directing compliance-related programs such as System Integrity, supporting the Company objectives of supplying safe, reliable, affordable, and clean energy to customers. Gas Asset Management provides necessary expertise and services in the areas of distribution and transmission system risk, engineering, and technical design standards, performs system load studies, and initiates augmentation projects to ensure the capacity of the gas distribution system can meet projected customer demands. Additionally, this area provides the technical expertise and coordination for public infrastructure projects initiated by third parties, such as cities, Michigan Department of Transportation ("DOT"), and large new industrial customers. Gas Asset Management includes System Integrity, which implements the SIMP, and is responsible for the storage wells and pipelines within the storage fields. Gas Compression Engineering is also a part of Gas Asset Management and is responsible for engineering of the Company's compressor station assets. The salaries and expenses of all the Gas Asset Management teams described above and the expenses for the SIMP for the 12 months ending October 31, 2026, are represented on Exhibit A-81 (KAP-2), pages 1 and 2, lines 2 through 7.

Q. Please describe the activities of the Gas Engineering - Distribution department.

A. The Gas Engineering - Distribution department consists of four sections. First, the Distribution Pipeline Engineering team is responsible for the design of all new and replacement gas mains and services across the Company's distribution system including customer requested service work. Second, the Gas System Engineering team is responsible for emergent engineering projects and operational support across the Company's distribution system. Third, the Design Quality and Contracts team is responsible for ensuring consistent and high-quality designs through review and coaching for the design technicians in Distribution Pipeline Engineering. The Design Quality and Contracts team also works on process development and technology improvement projects to make design teams more efficient. Additionally, this team owns the contracts for any outside engineering services needed to support the Distribution Engineering team. Fourth, the Distribution Engineering Services team is responsible for field support and field GPS data collection on installed gas distribution assets. The projected O&M expenses for the Gas Engineering – Distribution department for the 12 months ending October 31, 2026 is $730,000, as shown on Exhibit A-81 (KAP-2), page 1, line 2, and consists of the O&M portion of the salaries and expenses for engineers, designers, analysts, and other support staff needed to meet the design and planning needs of the NGDP.

Q. Please describe the activities of the Gas Engineering - Transmission department.

A. The Gas Engineering - Transmission department contains two sections. First, the Transmission Pipeline Engineering section is responsible for the engineering and design of the Company's transmission and storage pipeline facilities and supports the following transmission pipeline capital programs: Asset Relocation-Transmission, Deliverability Base Pipeline, Maximum Allowable Operating Pressure ("MAOP") Pipeline, MAOP Transmission (O&M), and Transmission Enhancements for Deliverability & Integrity ("TED-I"). The Transmission Engineering employees have responsibility for improving the pipeline system and ensuring compliance with applicable regulations. The second section is the MR&C team. MR&C is responsible for the engineering, design, and technical support of the Company's regulator stations, city gates, odorizers, and large customer meters through the following capital programs: Transmission City Gates, Distribution Regulator Stations, MAOP Metering & Regulation, and Deliverability Based Field Measurement. As described above, the Gas Compression & Storage technicians have been integrated into the MR&C team. The technicians are essential for maintaining the efficiency and safety of the gas system, ensuring smooth operations and quick responses to any issues that arise. This team performs critical work in monitoring, maintaining, and installing equipment in the gas system. Key duties include performing SCADA hardware/software monitoring, equipment inspections, configuration and commissioning of new equipment, providing technical support to Gas Operations staff, and ensuring work complies with policies, procedures, relevant safety standards, and regulations. My testimony covers the labor and expense costs for staffing of the Gas Engineering - Transmission department. The capital programs described above are sponsored by Company witness Michael P. Griffin. The projected O&M expenses for the Gas Engineering – Transmission department for the 12 months ending October 31, 2026 is $2,387,000, as shown on Exhibit A-81 (KAP-2), page 1, line 3, and consists of the O&M portion of the salaries and expenses for engineers, designers, analysts, technicians, and other support staff needed to meet the design and planning needs of the NGDP and the O&M expense for the purchase of odorant. The increase from 2023 historic year is due to the 2024 Company reorganization which moved the Gas Compression and Storage technicians to the MR&C team as described earlier in my testimony.

Q. Please describe the activities of the Gas Engineering Asset Planning department.

A. Gas Engineering Asset Planning is responsible for the development of long-range engineering programs, such as Gas Enhanced Infrastructure Replacement Program (“EIRP”) and Vintage Service Replacement (“VSR”), as well as coordination of annual projects across engineering organizations. Gas Engineering Asset Planning partners with Gas Operations and Gas Distribution Engineering to develop long-range projects. In addition, Gas Engineering Asset Planning partners with Gas Strategy to develop the NGDP. Gas Engineering Asset Planning is responsible for securing Right-of-Way permits for current Gas Distribution construction projects and works to negotiate favorable permitting requirements for future work. Gas Engineering Asset Planning is responsible for aligning project schedules and outages across asset classes, such as transmission and distribution, to create efficiencies and reduce the impact on customers. Gas Engineering Asset Planning is also responsible for the engineering and coordination of the Asset Relocation – Civic Program, as well as Distribution – Augment and Distribution – Compliance Base. The projected O&M expenses for the Gas Engineering Asset Planning department for the 12 months ending October 31, 2026, is $396,000 as shown on Exhibit A-81 (KAP-2), page 1, line 4, and consists of the O&M portion of the salaries and expenses for engineers, designers, analysts, and other support staff needed to complete the necessary engineering planning and permitting of projects outlined in the NGDP.

Q. Please describe the activities of the System Integrity department.

A. System Integrity is responsible for the integrity management programs for the Company. This includes the following programs: Transmission Integrity Management Program ("TIMP"), Distribution Integrity Management Program ("DIMP"), and SIMP. These programs ensure the integrity of the Transmission, Distribution, and Storage Assets. My testimony covers the labor and expense costs for staffing of the System Integrity department and the O&M expenses for the SIMP. The other System Integrity programs described above are sponsored by Company witnesses Griffin and Joyce. The projected O&M expenses for the System Integrity department for the 12 months ending October 31, 2026 is $3,789,000, as shown on Exhibit A-81 (KAP-2), page 2, line 5, and consists of the O&M portion of the salaries and expenses for engineers, designers, analysts, and other support staff needed to meet the design and planning needs of the NGDP including the implementation of the Transmission and Storage Probabilistic Risk Models and meeting compliance requirements of the Company's integrity management programs. The increase in O&M expenses from historical year 2023 is attributed to a departmental reassessment of work activities. This reassessment identified a rise in O&M inspections and remediation activities specifically related to integrity work. These activities are essential for maintaining the safety, reliability, and efficiency of operations, ensuring compliance with regulatory standards, and addressing any identified issues promptly.

In addition to the System Integrity staffing requirements, the SIMP was created in response to a new Pipeline and Hazardous Materials Safety Administration ("PHMSA") final rule issued on February 12, 2020. The SIMP O&M expenses for the 12 months ending October 31, 2026 is $2,129,000, as shown on Exhibit A-81 (KAP-2), page 2, line 7.

Q. What is the basis for determining the $2,129,000 in SIMP O&M expenses in the test year 12 months ending October 31, 2026 for this program?

A. On December 9, 2016, PHMSA issued an Interim Final Rule ("IFR") titled "Pipeline Safety: Safety of Underground Natural Gas Storage Facilities." This IFR included a new Rule 192.12 Underground Natural Gas Storage Facilities ("UNGSF") and was enacted as a congressionally mandated response to the natural gas leak incident at the Aliso Canyon facility on October 23, 2015. Rule 192.12 became effective January 18, 2017, and was incorporated by reference in the consensus document API RP 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. On February 12, 2020, PHMSA issued a Final Rule reinforcing its minimum safety standards for underground natural gas storage facilities and including additional requirements and clarifications. The effective date of this Final Rule was March 13, 2020.

As a result, Consumers Energy has developed the SIMP to comply with the federal regulations. The Company owns and operates 808 gas storage wells that fall under the scope of SIMP. The SIMP has several O&M components necessary to execute the program shown below in Table 1. The O&M components address the expenses required for the well plugging program, atmospheric corrosion protection (painting) of rehabilitated wells, risk reduction, annular pressure remediation, well re-assessment, and gas storage field analysis. The projected O&M costs for the SIMP in the test year total $2,129,000.

Table 1: SIMP O&M Program Components and Expenses

	12 Mos Ending Dec 31, 2023	Projected 12 Mos Ending Dec 31, 2024	Projected 12 Mos Ending Dec 31, 2025	Projected 12 Mos Ending Dec 31, 2026	Projected 12 Mos Ending Sept 30, 2026
Storage Integrity Management Program ("SIMP") ($000)	**$630**	**$1,956**	**$2,881**	**$2,555**	**$2,129**
a) Plugged Well Monitoring	$22	$60	$24	$53	$40
Units: # of CE Plugged Wells	85	82	56	125	93
Units: # of 3rd Party Plugged Wells	0	82	0	0	0
b) Atmospheric Corrosion Protection (Painting) of Rehabilitated Wells	$126	$80	$111	$19	$14
Units: # of Wells Painted	25	13	16	4	2
c) Risk Reduction	$184	$690	$1,520	$1,520	$1,138
Units: # of Farm Taps	30	31	75	75	60
Units: # of Storage Fields: Storage Lateral/Well Line (pipeline)	1	4	4	4	3
d) Annular Pressure Remediation	$94	$63	$143	$148	$123
Units: # of Wells (Assumes 15 Wells will require MIT's, 5 with wellhead seal replacements, remaining repacking of seals, includes labor costs for testing and repairs. Hanger replacements, tubing and/or packer replacements not included)	13	8	15	15	13
e) Well Re-assessment	$48	$898	$983	$712	$712
Units: # of Wells	0	105	108	79	79
f) Gas Storage Field Analysis	$158	$165	$100	$103	$102
Units: # of Storage Fields	1	2	1	1	1

Q. Please describe the plugged well monitoring portion of the SIMP funding requirements.

A. To comply with PHMSA Regulation 192.12 and API RP 1171, Consumers Energy has created a program to perform baseline assessment of well integrity as part of the Well Rehabilitation Program sponsored by Company witness Joyce. For all plugged wells within the storage reservoir boundary, the Company must further comply with plugged well monitoring requirements including the 390 plugged wells owned by the Company and the 740 plugged wells owned by other operators or producers. The monitoring of plugged wells includes visual and instrumented observation of the plugged well sites for any indication of methane leaks, changes in nearby observation well pressures, changes in annulus pressures of nearby facility wells, gas loss reported through the gas inventory verification process, and abnormally high gas production reported. The instrumented field monitoring will include 93 Company owned plugged wells in the test year. The average cost to monitor a Company owned plugged well is $259 and to monitor a plugged well owned by other operators or producers is $456. Additional costs associated with Third Party Plugged wells is due to the Company needing the ability to access property that it currently does not have rights to as the plugged wells that require instrumented monitoring were not owned or operated by the Company. In the test year, only plugged wells owned by the Company will be monitored. The O&M costs associated with the well plugging portion of the SIMP in the test year total $39,956 and are based on historical cost of performing monitoring.

Q. Please describe the well rehabilitation atmospheric corrosion portion of the SIMP funding requirements.

A. The well rehabilitation portion of the SIMP performs baseline assessment and remediation of Consumers Energy's natural gas storage wells. The O&M funding requirement is for painting of above-grade equipment associated with the rehabilitated wells to provide atmospheric corrosion protection upon completion of the assessment and remediation of a well where an asset is not intended to be retired or replaced. The projected cost is derived from the configuration of the well for applied corrosion control measures such as paint applied by contractors and inspection to ensure applied coatings meet the application specifications. The O&M costs associated with the well rehabilitation atmospheric corrosion portion of the SIMP for the projected test year totals $13,875.

Q. Please describe the risk reduction portion of the SIMP funding requirements.

A. The risk reduction portion of SIMP is to address facilities and piping that have compliance and safety risks associated with them. These facilities are associated with the storage system and include sections of the storage pipelines, well lines, and farm tap setups that fall outside of the ability to replace as a part of the capital SIMP programs due to being typically short sections of pipe or fittings installed as part of the original installation. The risk reduction portion will be used to investigate, evaluate, replace, or retire facilities to reduce risk on the storage system. The projected cost addresses risk on the system that does not fall into other areas of SIMP and includes approximately 75 farm tap facilities, short sections of transmission piping, and well lines. The costs include records validation, field research and physical verification, piping and equipment upgrades, replacements, repairs, and other associated charges. The O&M costs associated with the risk reduction portion of the SIMP for the projected test year is $1,137,826.

Q. Please describe the gas storage annular pressure diagnostics and remediation portion of the SIMP funding requirements.

A. The annular pressure diagnostics and remediation portion of SIMP is the cost of diagnosing and remediating wells that have annular pressures trending toward or exceeding threshold pressures. Annular pressure is monitored as part of SIMP and is a method to ensure integrity of the wells. Annular pressure outside of and trending toward threshold limits can indicate a loss of mechanical integrity or other failure requiring intervention. The diagnostic and repair funds are estimated based on historical spend, which typically requires testing, diagnosing, and repacking or replacement of wellhead seals. The O&M costs associated with the annular pressure diagnostics and remediation portion of the SIMP for the projected test year totals $122,641.

Q. Please describe the well re-assessment portion of the SIMP funding requirements.

A. The well re-assessment portion of SIMP is initiated seven years after the initial baseline assessment has occurred, in accordance with PHMSA Regulation 192.12 and API RP 1171. The well re-assessment portion of SIMP started in 2024. The wells that were baseline assessed in 2018 will be re-assessed in 2025, and wells baseline assessed in 2019 will be re-assessed in 2026. The re-assessment will consist of well logging and Mechanical Integrity Testing ("MIT") of the subject wells based on the configuration of each well and well history and includes any remedial and necessary actions. There is a total of 79 wells to be re-assessed in 2026, and all of them will be inspected and will incur costs in the test year. The O&M costs associated with the well re-assessment portion of the SIMP for the projected test year totals $712,452.

Q. Please describe the gas storage field analysis portion of the SIMP funding requirements.

A. The gas storage field analysis portion of the SIMP is an analysis used to model the storage system deliverability, considerate of all SIMP programs, and other related integrity programs. The purpose of the analysis is to better model the capability and needs of the existing storage system to enable right-sizing of the system and necessary equipment upgrades, including but not limited to well deliverability, field deliverability, pipeline replacements/retirements, liquid separation, and gas conditioning equipment. The analysis will support system risk reduction through optimization by matching existing and future system needs with the capabilities and future capabilities of the gas storage system. The gas storage field analysis portion of the SIMP for the projected test year totals $102,250.

Q. Please describe the activities of the Gas Compression Engineering department.

A. Gas Compression Engineering is responsible for the engineering, design, and technical support of the Company's compressor station assets. This team is also responsible for asset planning for all capital investments within the existing compression fleet. These capital investments are sponsored by Company witness Joyce. The increase in O&M expenses from historical year 2023 is attributed to additional labor required to perform a process hazard analysis of Northville Compressor Station that will occur in the test year of this case. The projected O&M expenses for the Gas Compression Engineering department for the 12 months ending October 31, 2026 is $1,015,000, as shown on Exhibit A-81 (KAP-2), page 2, line 6, and consists of the O&M portion of the salaries and expenses for engineers, designers, analysts, and other support staff needed to meet the design and planning needs of the NGDP.

Q. What operating sections are included in Gas Engineering Support?

A. Gas Engineering Support consists of five departments which I will describe more fully below. They are:

- Gas Strategy;
- Gas Regulatory and Compliance;
- Geospatial Management and Data Quality (which includes the Geospatial Inventory and Modeling Program);
- Damage Claims/Prevention; and
- Engineering Management.

Q. Please describe the activities of the Gas Strategy department.

A. Gas Strategy provides asset strategy, business support, financial analysis, and business performance measurement for the Company's compression, storage, transmission, and distribution facilities. This department is responsible for the development, implementation, and support of the long-term strategy for the natural gas system, and the development of the NGDP. This department ensures the overall goals and outcomes developed in the NGDP align with the Company's strategy. Gas Strategy includes the individuals responsible for ensuring that financial analysis aligns with the portfolio planning services, including long-term financial planning and long-term strategy. The projected O&M expenses for the Gas Strategy department for the 12 months ending October 31, 2026 is $89,000, as shown on Exhibit A-81 (KAP-2), page 2, line 8, and consists of the O&M portion of the salaries and expenses for strategy managers and analysts needed to support the financial analysis and business performance measurements necessary to ensure implementation of the NGDP as well as the long-term strategy development for the natural gas system.

Q. Please describe the activities of the Gas Regulatory and Compliance department.

A. Gas Regulatory and Compliance interfaces with the MPSC Gas Safety Staff and the Federal Office of Pipeline Safety on regulatory compliance matters. This includes regulatory audits, inspection activities, gas standards work, and submission of periodic and incident reports in accordance with both federal and state requirements. Gas Regulatory and Compliance supports compliance-related programs and documents, including Transmission Integrity Management, Distribution Integrity Management, Gas Operations Procedures, Public Awareness, and Damage Prevention. Effective September 1, 2023, the

AMD team was integrated into the Gas Regulatory and Compliance department from the Operations Compliance and Controls department. The Gas Regulatory and Compliance department is managing the Company's implementation of the API RP 1173 – Pipeline Safety Management Systems which is the Company's Gas Safety Management System ("GSMS") and the AMD Program. The salaries and expenses associated with the Gas Regulatory and Compliance department for the 12 months ending October 31, 2026 is $1,272,000 as shown on Exhibit A-81 (KAP-2), page 3, line 9. The 2023 historic expenses for this department, shown on Exhibit A-81 (KAP-2), page 3, column b, line 9, includes the September through December 2023 addition of the AMD team. The January through August 2023 historic expenses for the AMD team are included in Company witness Pnacek's Exhibit A-89 (JPP-4), page 1, line 1, Compliance and Controls. The projected O&M expenses include the full-year salaries and expenses for the AMD team added during the 2023 Company reorganization, reflecting the full-year impact of the additional staffing as described earlier in my testimony.

Q. Please describe the activities of the Geospatial Management and Data Quality department.

A. The Geospatial Management and Data Quality department is responsible for creating and maintaining the Geospatial Information Systems ("GIS") & Service Information Management System ("SIMS") databases for gas distribution, transmission, storage, service, and regulation systems, and for supporting strategic and operating capacity planning, performance, asset management, and regulatory reporting requirements.

The Geospatial Management and Data Quality department also supports the Company's gas technical records, working closely with operations and engineering teams to store, protect, retrieve, and, when appropriate, destroy records according to operational and regulatory requirements. In alignment with the above scope, the team has dedicated roles to manage system administration of Consumers Energy's Gas Engineering Content Management software. The O&M expenses for the Geospatial Management and Data Quality department for the 12 months ending October 31, 2026 is $645,000, as shown on Exhibit A-81 (KAP-2), page 3, line 10, and consists of the O&M portion of the salaries and expenses of managers and their Company-employed and contracted staff needed to support the increased asset records management to meet the compliance workload driven by the NGDP, and to ensure Company records are compliant and current, enabling employees and other end users to have comprehensive access to current and accurate mapping and correct information in a timely and cost-effective manner, all contributing to increased pipeline safety.

Additionally, this department is responsible for the Geospatial Inventory and Modeling Program, which includes the Gas Compliance Code Program – Service Information Mapping System ("GCCP - SIMS") project, and the Utility Network implementation. The O&M expenses for the Geospatial Inventory and Modeling Program within the Geospatial Management and Data Quality department for the 12 months ending October 31, 2026 is $518,000, as shown on Exhibit A-81 (KAP-2), page 3, line 11.

Q. What is the basis for determining the $518,000 of projected O&M expenses in the test year 12 months ending October 31, 2026 for the Geospatial Inventory and Modeling Program?

A. The Geospatial Inventory and Modeling Program includes the GCCP - SIMS project and the Utility Network project. This program was created to modernize and transform the

Company's GIS records and systems. This program has both a capital and O&M component. The projected capital expenditures and project benefits are described in further detail in the Gas Operations Other Program later in my testimony. The migration of gas service information to GIS is projected to be complete in early 2025. There are no projected expenses for the SIMS project in the test year of this case. The O&M expenses for the Utility Network project is $518,000 in the test year 12 months ending October 31, 2026. The projected costs for the GCCP - SIMS project was determined based on information provided to the Company in response to a Request for Proposal that was performed with several vendors in 2017, along with contracts put in place in 2022. The projected costs are updated annually as more work is defined and developed for the future state of the end-to-end solution. Total Utility Network transformation costs were estimated through an assessment performed in 2019 and 2020 in collaboration with Esri Professional Services ("Esri"). Esri prepared a high-level Utility Network migration strategy through a series of workshops in which the Company's business requirements, processes, and technical infrastructure were assessed to determine the scale and complexity of the migration. Upon completion of the workshops, Esri provided the Company with a written planning strategy along with a project schedule and cost estimate. In 2022 and 2023, the Company executed a Request for Proposal to further develop a business plan. The Company's current and future state was assessed along with performing a GIS data analysis to aid in further refining the projected costs, resource requirements, project timeline, and overall transformation strategy. The Company executed a Request for Proposal in 2024 to identify a qualified bidder to oversee, coordinate, and execute the modernization of the Company's existing Gas & Land Geospatial and corporate ArcGIS Enterprise platforms to the Utility Network (UN) data models hosted on Microsoft Azure. Due to the high level of impact and complexity of the change to people, processes, and technology, the Gas Utility Network transformation is planned to be complete in 2026.

Q. Please describe the activities of the Damage Prevention and Claims department.

A. Effective September 1, 2023, the Damage Prevention and Claims department was integrated into the Gas Engineering and Supply department from the Gas Operations Compliance and Controls department. The Damage Prevention and Claims department provides oversight of the Company's staking and locating of underground facilities in accordance with 811 MISS DIG regulations. This includes the Company's Gas Public Awareness Program. The O&M expenses for the Damage Prevention and Claims department for the 12 months ending October 31, 2026 is $1,231,000, as shown on Exhibit A-81 (KAP-2), page 3, line 12, and consists of the O&M portion of the salaries and expenses for roles needed to support damage prevention/claims activities and liaison with external agencies and excavators, and the public promoting of education and awareness to proactively prevent and reduce third-party damages. The 2023 historic year expenses for this department shown on page 3, column (b), line 12 of the exhibit, represent expenses from September through December 2023. The January through August 2023 historic year expenses are included in Company witness Pnacek's Exhibit A-89 (JPP-4), page 1, line 1, Compliance and Controls. The projected O&M expenses include the full-year salaries and expenses, and software licensing expenses, for the Damage Prevention and Claims team added during the 2023 Company reorganization, reflecting the full-year impact of the additional staffing as described earlier in my testimony.

Q. Please describe Engineering Management.

A. The Engineering Management department includes the O&M expenses associated with the roles of the Vice President of Engineering and Supply and their support staff. The expenses include the O&M portion of salaries and associated expenses needed to support a range of critical responsibilities, including oversight of:

- Engineering of the Company's natural gas system distribution, transmission, storage, and compression assets;
- Procurement and supply of natural gas;
- Strategic planning;
- Budgeting and financial management;
- Setting performance goals, providing professional development opportunities, and fostering a collaborative and innovative work environment; and
- Ensuring all operations comply with federal, state, and local regulations.

These responsibilities ensure safe, efficient, and reliable delivery of natural gas to customers. The O&M expenses for the Engineering Management department for the 12 months ending October 31, 2026 is $46,000, as shown on Exhibit A-81 (KAP-2), page 4, line 14.

Q. What operating sections are included in Gas Management Services?

A. Gas Management Services is responsible for four major functions:

- Gas Control;
- Gas System and Operations Planning;
- Gas Supply; and
- Gas Transportation, Customer Choice, and Measurement.

Gas Control is responsible for:

- The centralized Gas Control Room operation, which monitors and controls the gas transmission system and monitors key points on the distribution system on a 24/7 basis, following PHMSA Title 49 CFR 192.631 (control room management);

- Monitoring scheduled third-party pipeline supply;

- Dispatching compression and storage assets to ensure customer supply is met within the Transmission system's design limits and monitoring portions of the Distribution system; and

- Gas SCADA development, including operations and 24/7 support.

Gas System and Operations Planning is responsible for:

- Transmission and storage capacity studies;

- Facility and operational improvements to meet changing supply and customer loads;

- Reporting operational data;

- Assisting in development of business cases for major system modifications related to the Company's gas transmission, storage, and compression system;

- The preparation of natural gas supply and storage dispatch plans;

- The coordination of the Gas Cost Recovery ("GCR") plan and GCR Reconciliation with the Company's operational plans; and

- Administration of interconnect agreements.

The Gas Supply section is responsible for:

- Obtaining reliable and reasonably priced gas supply for the Company's GCR or Sales customers;

- Negotiation and administration of all related gas supplier, transportation, and Buy/Sell agreements, and Asset Management contracts; and

- Tracking and projecting the cost of gas and related inventory valuations, Gas Supply coordinates the gas purchase planning related to GCR plans and reconciliations.

The Gas Transportation and Measurement section is responsible for:

- The management of the Company's Gas Customer Choice ("GCC") Program, including preparation of required deliveries for GCC Suppliers, and monthly GCC remittance statements and annual reconciliations;
- The daily management of the gas transportation activity at the Company, including the daily balancing and confirmation of gas nominations and gas transportation contract administration; and
- The preparation of the Gas Control Operations Summary and various internal and external reports, all of which make up the foundation of volumetric accounting on the Company's gas transmission and storage system.

The salaries and expenses associated with the Gas Management Services department for the 12 months ending October 31, 2026 is $4,796,000, as shown on Exhibit A-81 (KAP-2), page 4, line 15, and consists of the O&M portion of the salaries and expenses for engineers and gas control staff needed for outage coordination, scheduling, and system planning activities necessary to support the capital, O&M, system control, and system analytics plans in the NGDP. The projected O&M expenses include the full-year salaries and expenses, and software licensing expenses, for the OT Gas SCADA team added during the 2024 Company reorganization, reflecting the full-year impact of the additional staffing as described earlier in my testimony.

GAS DISTRIBUTION CAPITAL EXPENDITURES

Q. Please describe the Company's projections of capital expenditures for Gas Distribution – Material Condition and Gas Operations Other.

A. As shown on Exhibit A-12 (KAP-3), Schedule B-5.8, the Gas Distribution capital expenditures I am sponsoring were $274,046,000 in 2023, and are projected to be $301,775,000 in 2024; $313,809,000 for the 10 months ending October 31, 2025; and $402,755,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 3, columns (b), (c), (d), and (f), respectively. These projections are based upon the necessary requirements to meet the Company's objectives of operating a system that is safe, reliable, affordable, and clean.

Q. Please list the major programs within the Gas Distribution capital expenditures.

A. The major programs, as shown on Exhibit A-12 (KAP-3), Schedule B-5.8, and Exhibit A-12 (LDW-1), Schedule B-5.9, are:

- New Business;
- Asset Relocation;
- Regulatory Compliance;
- Material Condition;
- Capacity/Deliverability; and
- Gas Operations Other.

Several of these major programs have a gas distribution and a gas transmission component to them. My direct testimony represents only the gas distribution portion of the Material Condition and Gas Operations Other programs. The direct testimony of Company witness Warriner represents the gas distribution portion of the remaining programs listed above. The direct testimony of Company witnesses Griffin and Joyce represent additional components of the gas transmission system as well as distribution regulating stations, compression, and storage systems.

Q. Have you included contingency costs in the capital expenditures you are sponsoring?

A. No, there are not any contingency costs included in the capital expenditures.

1. <u>Material Condition</u>

Q. Please describe the capital expenditures relating to the Material Condition Program set forth on Exhibit A-12 (KAP-3), Schedule B-5.8, line 1.

A. Material Condition Program expenditures are used to improve the natural gas distribution system integrity, reduce service interruptions impacting customers, and replace leaking and vintage gas distribution facilities. Reducing the number of leaks improves reliability, reduces methane emissions to the atmosphere, and enhances public safety. The expenditures in this program include the EIRP, the VSR Program, and system enhancements that are prioritized by risk to improve safety and gain operational efficiencies through replacement of lower performing gas distribution assets.

The expenditures in this program also include capital replacements due to leaks and system damages, represented by the Material Condition Renewals Program, as well as emergent gas service and main replacement projects driven by conditions observed in the field, represented by the Material Condition Non-Modeled Program, and business customer capital meter and meter stand replacements represented by the Commercial and Industrial Meters Program. The projects and expenditures for these five programs are described in more detail below. As shown on Exhibit A-12 (KAP-3), Schedule B-5.8, line 1, the capital expenditures for these five programs were $266,297,000 in 2023, and are projected to be $285,681,000 in 2024; $301,865,000 for the 10 months ending October 31, 2025; and $385,665,000 for the test year 12 months ending October 31, 2026, as set forth on this exhibit on line 1, columns (b), (c), (d), and (f), respectively. The expenditures for the Material Condition Program are further detailed in Exhibit A-82 (KAP-4).

Q. Please describe the EIRP.

A. Beginning in 2012, the Company implemented the EIRP to ensure continued customer safety and reliable system operation as part of the DIMP. The EIRP replaces the Company's highest risk materials as classified by PHMSA, including all cast iron, wrought iron, Threaded and Coupled ("T&C"), oxyacetylene welded, copper, and bare steel distribution main with more reliable, lower maintenance plastic and steel main, and replaces (in the case of older metallic materials) or ties-over (plastic) services to the new main.

The program scope includes the following:

- Replacement of all cast iron main;
- Replacement of all bare, oxyacetylene welded, T&C, Xtrube, and cathodically unprotected steel main;
- Replacement of all copper main;
- Replacement of metallic service materials associated with the main replacement projects;
- Replacement of approximately 100 miles of transmission pipeline located in high consequence areas and transmission pipelines operated on the Distribution System;
- Replacement of approximately 70 miles of low frequency electric resistance weld pipe in the Company's Transmission and Storage fields; and
- As included in the Company's NGDP, elimination of the standard pressure system which includes replacement of approximately 105 miles of pipe that is not covered in the vintage main miles and 68 miles of plastic to be converted from standard pressure (SP) to medium pressure (MP). The Company intends to complete this work and include it as part of planned EIRP work.

In addition to safety and reliability improvements, replacement of cast iron piping will enable the reduction and eventual elimination of the standard pressure system, allowing these areas to operate at higher, more efficient pressures while lowering gas losses, reducing the potential for water infiltration, and reducing greenhouse emissions. Upgrades to more efficient pressures may require modifications to regulator facilities under this program. Eliminating standard pressure also allows for the elimination of certain regulating stations that feed the standard pressure system, which lowers operating costs for those systems.

EIRP projects are selected by the gas engineering teams using a risk model that assesses the risks and threats of each pipe segment, according to the Company's DIMP. The risk model helps prioritize system replacements to eliminate the highest risk distribution pipe first, to maximize the system risk reduction in any given year. The Company uses this risk-based approach, combined with subject matter expert input, to select EIRP replacement projects that eliminate vintage mains and standard pressure systems. The EIRP investment ensures reliability and the safety of customers and the public. The well-planned, thoughtful execution of the EIRP is a more cost-effective approach than being forced into replacement under emergent conditions. The Company continues to evaluate the risks to the distribution system along with the overall timeframe projected to replace higher risk pipe.

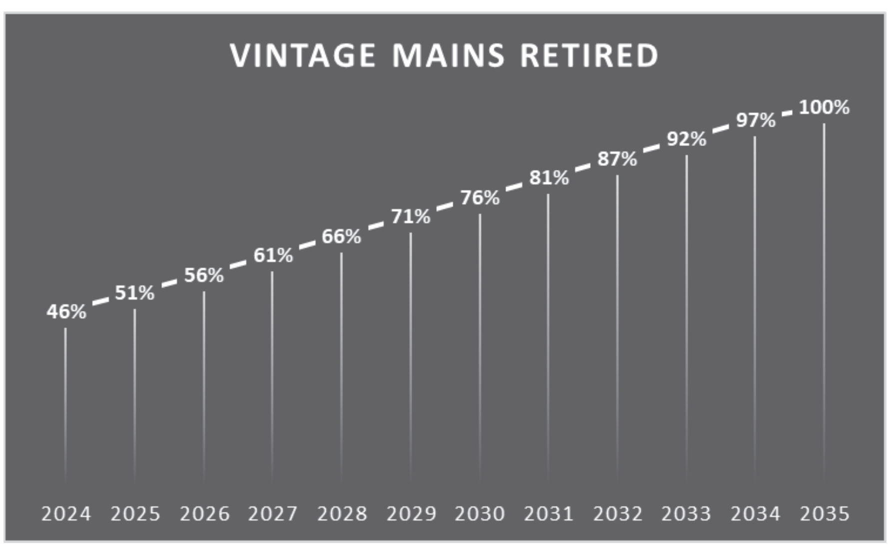
Q. Please describe the progress of the EIRP.

A. Since the EIRP began in 2012 through the calendar year ended 2023, the program has retired 794 miles of the vintage gas pipe identified for replacement as shown in Table 2. In addition to the EIRP, other programs, like Asset Relocation – Civic Improvement and Material Condition Non-Modeled, also eliminate vintage pipe. In any given year, the number of miles retired for each material will vary based on the mix of investment between steel and plastic projects. The Company uses a risk model to optimize the investment to eliminate higher risk gas mains first. At the end of calendar year 2023, the status for each of the main types is detailed as follows:

- Copper main – Eliminated the last known copper main segments in 2018;
- Xtrube main – Eliminated the last known Xtrube main segments in 2018;
- Cast iron main – Eliminated 286.7 of 580.0 miles by the EIRP through 12/31/2023;
- Wrought iron main – Eliminated 5.3 of 21.6 miles by the EIRP through 12/31/2023;
- Bare steel main (including oxyacetylene welded bare steel) – Eliminated 286.3 of 1033.4 miles by the EIRP through 12/31/2023; and
- T&C main – Eliminated 148.8 of 1061.7 miles by the EIRP through 12/31/2023.

As described in the NGDP, completing the EIRP by 2035 enhances safety and reliability while also balancing affordability. This balance is achieved by managing costs and prioritizing investments that provide the greatest benefit to customers without extending the overall project duration and associated costs, ultimately minimizing the cost impact to customers. The EIRP is currently planned to be completed by the end of 2035, reducing vintage main miles by approximately 5% per year.

Figure 1: Vintage Main Replacement Pace 2024 - 2035



See Table 2 below for a summary of pipe retired each year by the EIRP Program and the cumulative pipe retired by other programs.

Table 2: Miles of EIRP Main Pipe Retired by Year

MILES OF EIRP CLASSIFIED MAIN PIPE REPLACED BY YEAR								
PIPE TYPE:	Miles of Pipe by Pipe Type in EIRP Program Scope	EIRP Actual (2012 -2020)[1]	EIRP 2021 Actuals[1]	EIRP 2022 Actuals[1]	EIRP 2023 Actuals[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
TOTAL:	2869.2	499.7	119.1	84.3	91.1	794.1	401.0	1,674.1
Cast Iron	580	180.4	50.6	23.0	32.7	286.7	101.8	191.5
Bare Steel	1033.4	161.8	46.4	56.1	22.0	286.3	129.8	617.3
Threaded & Coupled	1061.7	100.1	14.9	4.2	29.7	148.8	163.0	749.9
Wrought Iron	21.6	4.7	0.4	0.0	0.2	5.3	5.8	10.5
X-trube	0.9	0.9	0.0	0.0	0.0	0.9	0.0	0.0
Copper	1.6	0.6	0.0	0.0	0.0	0.6	0.5	0.0
Coated & Wrapped on Standard Pressure[3]	108.35	(34.2)	1.2	2.2	3.2	(27.6)		
TOD	100	12.8	6.7	1.1	6.5	27.1		
LFERW	70	38.4	0.0	0.0	0.0	38.4		
Additional Pipe Replacement:								
Plastic[2]		10.1	3.2	6.6	9.8	29.7		
Coated & Wrapped[2]		83.5	12.4	39.5	25.2	160.6		

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) Coated & Wrapped steel pipe on standard pressure does qualify under ERIP while Coated & Wrapped steel pipe on medium pressure does not qualify under EIRP

In 2023, the Company completed 13 projects using the grid approach, which plans for and constructs large scale EIRP projects (typically 15 to 25 miles of distribution pipeline). Opportunities to use the grid approach for future projects are decreasing due to the location of higher risk pipe. A shift back to more segment projects will begin in 2025. The Company will continue to apply efficiencies achieved through prior years (described later in this testimony) to mitigate unit costs.

Q. Please explain the difference between replaced or retired pipe and installed pipe for the EIRP and why cost is based on installed pipe.

A. Replaced or retired pipe refers to the amount of vintage pipe existing on the Company's gas system prior to EIRP project construction that will be replaced by newly installed pipe and retired (abandoned in place) upon completion of the EIRP project construction. Miles of replaced or retired pipe by the EIRP is included in Table 2 above and as part of the Company's annual performance report filings. Installed pipe refers to the amount of new pipe that is added to the Company's gas system to replace the vintage material pipe being retired upon completion of the EIRP project construction. The EIRP project cost is based on installed pipe, as the EIRP project activities are related to the planning, design, and construction for the new pipe installation. There is a small amount of construction time related to the retirement activity to safely cut and cap the old vintage pipe to retire the pipe (abandon in place). The Company charges 2% of EIRP project cost to cost of removal ("COR") to cover the cost related to the retirement activities, which is included in the Company's depreciation rate cases, and not included as part of the EIRP project cost in this testimony. The EIRP project costs provided in this testimony are without COR and related to the project planning, design, construction, and other activities to support the new pipe installation.

Q. What were the results of the 2023 EIRP projects?

A. In 2023, the Company constructed 13 EIRP projects using the grid approach, and one Steel/TOD project. See Table 3 below for a summary of the scope of the 2023 EIRP project work completed.

Table 3: 2023 EIRP Program Completed Project Work

Project Type	# Projects	Installed Pipe (miles)	Service Counts
Grid Projects	13	102.3	8,649
Segment Projects	0	0	0
Steel/TOD Projects	1	6.6	0
Total	**14**	**108.9**	**8,649**

As shown in Exhibit A-84 (KAP-6), the 2023 EIRP spend was $181.9 million. Program costs include previous year project carryover expenses, current year project expenditures, and future year project expenditures. The previous year project carryover expenses include activities such as pipe installation, pipe retirement, and surface restoration that could not be completed during the prior construction year. In addition to new pipe installation, the current year project expenditures include activities, such as standard pressure system conversions and meter move outs, which have no attributed miles or service counts but contribute cost to the cost-per-mile calculation. However, these activities are necessary for project completion. The future year project expenditures include activities such as engineering, survey, and construction mobilization that must be completed prior to the start of construction. Like standard pressure system conversions and meter move-outs, these necessary activities result in additional project expenditures with no associated installed miles, increasing the total EIRP average cost per mile each year. As shown in Exhibit A-84 (KAP-6), a total of 108.9 miles were installed in 2023. Of the program expenditures of $181.9 million, $176.6 million was spent on 2023 projects with carry-over and future year expenditures amounting to $5.4 million. This results in an overall cost of $1.67 million per mile. For 2023 plastic pipe installation, the regional per-mile expenditures were $2.3 million, $1.4 million, and $1.5 million for the Southwest, Northeast, and Southeast regions, respectively, resulting in a weighted average of $1.63 million per mile. The higher per mile expenditures in the Southwest region was due to a large quantity of standard pressure conversion work in the Lansing area. For the steel project completed in 2023, the per-mile cost was $1.55 million. The lower steel cost-per-mile was primarily due to the project's rural location, which made construction less difficult and did not require significant pre- or post-construction activities.

Q. What factors influence the installed cost per mile for EIRP distribution projects?

A. There are many factors that can influence the installed cost per mile of EIRP distribution projects. When looking at unit cost data, it is important to consider these factors to help understand the complexity and variability of costs incurred in performing the project work. Some of the key factors to consider are listed below.

- Location – The urban density of the area where a project is executed has a significant influence on the cost of that project. Some of the differences include:
  - Rural projects – Little or no hard surface (sidewalks), few obstacles in the ground, typically lower permitting costs and requirements;
  - Suburban projects – Mostly residential and some commercial services, moderate hard surface with potential for installation under sidewalks or streets, moderate traffic control and safety services cost, low to moderate obstacles in the ground (other service provider wires, pipes, etc.), moderate permitting cost and number of requirements;
  - Urban projects – Commercial and residential buildings and services, significant hard surface requiring installation under sidewalks and streets, high traffic control and safety services cost, high obstacles in the ground (other service provider wires, pipes, etc.), moderate to high permitting cost and number of requirements; and
  - Inner city projects – Buildings and commercial services, significant hard surface requiring installation under sidewalks and streets, high traffic control and safety services cost, significant obstacles in the ground (other service provider wires, pipes, etc.), high permitting costs and number of requirements.

- Number of associated services – The average number of services to be renewed with the installed main is a significant driver of project cost, as every service renewal requires material and labor time, and contributes to the required support services needed for a project (such as sewer locates, hydrovac excavation, aggregates, and soft and hard surface restoration). A project with 50 services per mile will contribute less cost related to service renewals than a project with 100 services per mile.

  - Additional considerations include if the services are long side (crossing the road from the installed main location) or short side (same side of the road as the installed main), the number of services on a project that are tie-over (connecting a previously installed plastic service line to the new installed main) versus renewal (replacing vintage service pipe), and whether a service is residential or commercial (requires a different meter and larger service pipe diameter than residential).

  - Completion of long side services typically takes longer and costs more than short side, renewals typically take longer and cost more than tie-overs, and commercial services typically take longer and cost more than residential services.

  - Commercial services require more costly equipment and material, a higher skilled employee, and more coordination with the business owner.

  - Exhibit A-84 (KAP-6) provides data on services worked on through the EIRP Program for 2018 - 2023 and a projection of 2024 through 2026 sorted by Michigan regional locations where the work is located (SW is primarily the Jackson, Lansing, Kalamazoo areas; NE is primarily the Flint, Saginaw, Midland, and Bay City areas; and SE is primarily the Royal Oak, Macomb, Livonia areas).

- Pipe type – High pressure ("HP") steel segment and Transmission Operated by Distribution ("TOD") pipe installation is significantly more complex and expensive than plastic pipe installation. In addition, pipe being retired may cause cost variations as well. For example, steel pipe may require end caps and pressure control fittings to be installed before retiring, whereas cast iron requires less resources to retire.

- Pipe size – As the size of installed pipe increases, the cost of material, labor, and associated supporting services also increase due to additional time, and in some cases, higher skilled labor, required to install the larger size pipe.

  - The most common main pipe size installed on EIRP projects is 2-inch plastic; however, a large amount of 4-inch and 6-inch plastic is also installed.

– For larger plastic pipe, typically 8-inch and larger (but also some 6-inch), the pipe to be installed is not in coil form (typically 500 ft in length) but is in individual segments or "sticks" (typically 40 ft). This requires more fusing time for these lengths as well as a more complex fusing process and equipment (hydraulic fusing).

– Steel pipe size installed varies based on the design requirements of the project and is typically 10-inch or larger.

– Tables 4 and 5 below provide data on the feet of pipe installed through the EIRP Program for the years 2017 through 2023.

Table 4: EIRP Feet of Pipe Installed by Size, Type, Year

Year/ Size	2"P	4"P	6"P	8-12"P	2-6"S	8"S	10"S	12"S	16"S	Total
2017	344,644	44,231	11,768	3,231	700	0	0	225	0	**404,799**
2018	195,527	25,216	30,939	2	129	0	10,057	546	16,685	**279,101**
2019	192,783	32,619	32,535	1,526	386	0	8,121	12	0	**267,982**
2020	303,001	34,612	18,831	3,572	0	4,127	7,637	4,371	0	**376,151**
2021	698,773	44,554	52,279	10,620	922	428	100	22,426	0	**830,102**
2022	699,278	62,528	76,995	9,360	1,283	6,503	2	0	0	**855,949**
2023	446,536	32,497	55,590	5,624	13	28	74	34,833	0	**575,195**
Total	**2,880,542**	**276,257**	**278,937**	**33,935**	**3,433**	**11,086**	**25,991**	**62,413**	**16,685**	**3,589,279**

Table 5: EIRP % of Pipe Installed by Size, Type, Year

Year/ Size	2"P	4"P	6"P	8-12"P	2-6"S	8"S	10"S	12"S	16"S	Total
2017	85.1%	10.9%	2.9%	0.8%	0.2%	0.0%	0.0%	0.1%	0.0%	**100.0%**
2018	70.1%	9.0%	11.1%	0.0%	0.0%	0.0%	3.6%	0.2%	6.0%	**100.0%**
2019	71.9%	12.2%	12.1%	0.6%	0.1%	0.0%	3.0%	0.0%	0.0%	**100.0%**
2020	80.6%	9.2%	5.0%	0.9%	0.0%	1.1%	2.0%	1.2%	0.0%	**100.0%**
2021	84.2%	5.4%	6.3%	1.3%	0.1%	0.1%	0.0%	2.7%	0.0%	**100.0%**
2022	81.7%	7.3%	9.0%	1.1%	0.1%	0.8%	0.0%	0.0%	0.0%	**100.0%**
2023	77.6%	5.6%	9.7%	1.0%	0.0%	0.0%	0.0%	6.1%	0.0%	**100.0%**
Total	**80.3%**	**7.7%**	**7.8%**	**0.9%**	**0.1%**	**0.3%**	**0.7%**	**1.7%**	**0.5%**	**100.0%**

- Permitting requirements – These vary from community to community and have the potential to significantly impact project costs. Municipalities have expanded the scope of permitting requirements, moving to more specific permitting (by address / premises), permitting fees have increased, and the more detailed requirements result in increased cost to projects. Also, some communities have placed permit conditions that require dual mains be installed on projects, resulting in significant increases to the cost of those projects.

- Time of year – Challenging weather conditions in the winter, spring, and late fall (such as cold, snow, thunderstorms, heavy wind and rain, and poor ground conditions) can slow production and lead to increased project cost. Additionally, to reduce customer outages during critical heating seasons, the Company transitions into "winter operations" typically in early November (temperature dependent), which requires customer appointment and presence to perform the work. This adds costs as it can require labor resources to work during non-regular time, resulting in overtime and premium time.

- Standard pressure conversions - A standard pressure conversion is a cost-saving measure used by the Company during standard pressure replacement projects. When there is existing plastic pipe within the project area, the Company assesses whether these can be converted to medium pressure instead of being replaced. If the existing plastic pipes are still within their usable life cycle, converting them is more economical than installing new plastic pipes. Although this conversion work increases the cost-per-mile of a project, since it doesn't involve laying new pipes, it ultimately reduces overall costs by avoiding the need for all-new plastic piping.

Some additional drivers of costs include:

- Sewer location services – As with all utilities, Consumers Energy locates underground facilities in advance of construction work. Locating sewer mains, laterals, and services helps to protect those facilities from damage such as cross-bores and leaves customer sewer lines intact. Sewer locating services are contracted to third-party vendors for this work and are primarily performed for the location of sewer mains at the onset of the program.

- Dual main installation - Some communities have placed conditions in the permits for projects that require the Company to install main on both sides of the road when replacing and retiring the existing vintage main, which historically was only required to be installed on one side of the road. This requirement in effect doubles the footage of main pipe installation for a project, increasing the cost of materials, labor, and the supporting services for the project.

- Cross bore inspections – This work helps ensure that Company Gas facilities were not installed through sewer lines or other utilities while using horizontal directional drilling pipe installation techniques. Given the potential risk with cross bores, the Company is inspecting for them after construction work is completed (though all other underground facilities are now being located and marked) to ensure public safety, which is adding to costs.

Q. Will all the remaining EIRP Program work be completed using the grid approach?

A. No. It will always be necessary to have certain project work completed using the segment project approach. The grid approach can be used in areas where the Company has a high concentration of EIRP vintage main distribution pipe to be replaced, allowing for the design and planning of large projects. As EIRP work is completed in the high concentration areas, it will be necessary to complete the replacement of vintage main distribution pipe in areas where the Company only has a small amount of EIRP pipe to replace. The Company also considers pipe risk in its planning and project selection criteria, which will result in some amount of segment projects to be completed each year based on risk selection. The Company is also replacing HP steel pipe and TOD pipe as part of the EIRP, and that work is planned as segment projects. For the test year of November 1, 2025 through October 31, 2026, a significant amount of the planned project work to be completed by the EIRP will be using the segment project approach and that is the basis for the Company's current test year cost projection.

Q. Is the Company planning to complete high pressure steel and other pipe replacement work within the EIRP Program?

A. Yes. The Company plans to complete HP steel and TOD steel pipe projects in 2024, 2025, and 2026. In 2024, the GVL1 segment project includes 7 miles, and the MAC3 segment project contains 1.24 miles of HP steel pipe installation. In 2025 and 2026, the Company is planning several projects with varying lengths of HP steel pipe replacement, totaling 21.5 miles and 14.1 miles, respectively. See Table 6 below for a summary of the 2024 to 2026 EIRP steel project work planned. A listing of the specific projects is included in workpaper WP-KAP-3.

Table 6: 2024 – 2026 EIRP HP/Steel Project Miles

	# Projects	Southwest	Northeast	Southeast	Total Miles
2024	2	7.04	0	1.20	8.24
2025	12	4.5	16	1	21.5
2026	8	10.5	2.5	1.1	14.1

Q. Has the Company taken actions to improve the cost per mile in the EIRP since the filing of Case No. U-21308?

A. Yes, the Company has implemented changes expected to mitigate the cost-per-mile for EIRP projects. The Company has taken the following actions:

- Engineering design timing – the Company has advanced the engineering design process so that EIRP project designs are completed the year prior to construction. This provides partnering teams such as Supply Chain, Permitting, and Operations more time to focus on planning the execution phase of the project, including materials management, sequencing of the construction phases, aligning workforce resources, arranging outside services, and other activities.

- Engineering designs – the Engineering team has implemented design checkpoints at thirty, sixty, and ninety percent completion milestones. The checkpoints provide opportunities for analysis, evaluation, and feedback by stakeholders, allowing the Engineering team to alter designs, if necessary, throughout the design process.

- Distribution Engineering Services – created a dedicated team to support field resources in construction planning, collecting asset information, making design adjustments, and completing as-built records. This provides real-time input and adjustments with engineering resources to increase efficiency and reduce unit costs.

- Redistributed Company headquarters for the Gas Construction Workforce – the Company has redistributed the Gas Construction headquarters to move the workforce closer to the projects based on the updated work plans. This allows the workforce to be repositioned closer to the worksite, thereby reducing travel and other related costs. In 2022, travel and lodging costs totaled $1.8 million. In 2023, these costs were reduced to $480,416, saving over $1.3 million. For 2024, travel and lodging costs are projected to be $690,422, which is a projected savings of $1.1 million compared to 2022 levels. The new headquarters will be used for the remainder of the EIRP, with a projected annual savings of $1 million in travel and lodging from 2022 levels. The facilities' projected total cost is $11 million, but the projected savings in travel and lodging of $13 million results in an overall savings of $2 million. Information on the additional EIRP Company headquarters can be found in the testimony and exhibits of Company witness Quentin A. Guinn.

- Gas Construction workforce stabilization – the workforce capacity is enhancing due to stability in the project layout, ability to pre-plan the work because of earlier designs, and productivity learnings from the EIRP grids.

Q. What cost per mile is the Company currently projecting for the EIRP projects?

A. As shown in Exhibit A-84 (KAP-6),

For SP/MP projects (plastic pipe):

- 2023: The overall project cost-per-mile for installed plastic pipe was $1,625,519.
- 2024: The projected overall cost-per-mile is $1,353,912 for installed plastic pipe. This is based on regional costs of $1,306,077 (Southwest), $1,382,187 (Northeast), and $1,365,542 (Southeast).
- 2025: The overall projected cost-per-mile is $1,357,800, with no escalation in projected regional cost-per-mile due to process improvements.
- 2026: To account for anticipated increases such as inflation, supply chain, and labor cost, a 3% increase is applied to 2025 regional cost-per-mile, resulting in a projected overall cost-per-mile of $1,404,251, which is still less than the 2023 actual cost per mile.

For HP steel/TOD projects (steel pipe):

- 2024: The projected cost-per-mile is $1.98 million for the GVL1 project and $4.56 million for the MAC3 project.
- 2025: The cost-per-mile is projected at $3.8 million, based on the average of the cost-per-mile from 2018 to 2023 steel projects.
- 2026: To account for anticipated increases such as inflation, supply chain, and labor cost, a 3% increase is applied to 2025 cost-per-mile, resulting in a projected cost-per-mile of $3.91 million.

Q. What is the Company's projected EIRP cost for the test year 12 months ending October 31, 2026?

A. The capital expenditures for EIRP were $181,926,631 in 2023 and are projected to be $195,587,000 for 2024; $207,322,000 for the 10 months ending October 31, 2025; and $251,372,000 for the test year 12 months ending October 31, 2026. The costs for the EIRP are set forth on Exhibit A-82 (KAP-4), line 1. As shown below in Table 7, the test year projects 149.0 installed miles and renewal of 9,175 services.

Q. How many miles of distribution main installation and associated services does the Company plan to complete for the $251.4 million investment for the test year?

A. The referenced $251.4 million supports the annual installed mileage required to ensure program completion by 2035. The Company prepares its estimates and projections based on calendar years running from January 1 through December 31. For the test year of November 1, 2025, through October 31, 2026, the Company combined a prorated projection for two months of 2025 and a prorated projection for the ten months of 2026 to provide the projected miles installed and service figures. The projection methodology is based on the monthly cash flow average percentage, using the three-year historical period of 2021 through 2023. The derivation of the test year projection is 17% of the 2025 projection and 83% of the 2026 projection.

- The Company's projection for the calendar year 2025 includes 142.0 miles of main installation and 12,528 associated services. There are 12 HP Steel/TOD segment projects for 21.5 miles. The remaining 2025 projects include an additional 120.5 miles of plastic pipe installation.
- The Company's projection for the calendar year 2026 includes 150.3 miles of main installation and 11,903 associated services. There are eight HP Steel/TOD segment projects for 14.1 miles. The remaining 2026 projects include an additional 136.2 miles of plastic pipe installation.
- While total miles and services are subject to final project designs and construction schedule, based on the current projections the test year is estimated to include approximately 149.0 miles of main installation and 9,175 associated services.
- Table 7 below provides a summary for the years 2023 through 2026 and the test year.

Table 7: EIRP 2023-2026 Scope and Cost

	Actual	Projected	Projected	Projected	Projected	Projected
Year	2023	2024	2025	2026	10 months 1/1/25-10/31/25	Test Year 11/1/25 – 10/31/26
Installed Pipe (Miles) [1]	108.9	134.6	142.0	150.3	117.6	149.0
Service Counts [1]	8,649	12,114	12,528	11,903	8,748	9,175
Capital Cost ($Millions) [2]	$181.9	$195.6	$250.3	$251.6	$207.3	$251.4

1 Includes total figures for all EIRP Program pipe installation and service counts for a year

2 Includes total EIRP capital spend without COR (cost of removal) for a year

Q. Please highlight the customer benefits of the vintage main distribution pipe and services replacement.

A. Major gas utilities throughout the country are embarking or undergoing major replacement projects, and some utilities are undertaking these projects under urgent timeframes due to incidents on their systems. The well-planned, thoughtful execution of the EIRP is a more cost-effective approach than being forced into replacement under emergent conditions for several reasons including:

- Cost Control: Planned replacements allow for better budgeting and cost management. The Company can negotiate better prices for equipment and services, avoiding the premium costs often associated with emergency procurements.
- Minimized Downtime: Scheduled replacements can be coordinated to minimize operational and customer disruptions. In contrast, emergent replacements often result in unexpected downtime, which can be costly in terms of lost productivity and potential extended customer outages.
- Resource Allocation: With a planned approach, the Company can allocate resources more efficiently, ensuring that skilled personnel and necessary tools

are available when needed. Emergencies often require pulling resources from other projects.

- Risk Management: Proactive planning helps identify potential issues before they become critical, reducing the risk of catastrophic failures that can be far more expensive to address.

By taking a proactive approach, the Company can avoid the high costs and operational disruptions associated with emergency replacements. This leads to more efficient and cost-effective operations while minimizing the impact of service disruptions to customers. The Company continues to evaluate the risks to the distribution system along with the overall timeframe projected to replace higher risk pipe. Through December 31, 2023, the Company has replaced 794 miles of high-risk pipe identified for replacement through the EIRP, including 287 miles of cast iron and nearly 96,850 services replaced and retired to improve reliability and customer safety.

Q. Does the Company expect to meet the spending and installed miles requirements for EIRP from the Case No. U-21308 settlement agreement?

A. Yes, the settlement agreement from Case No. U-21308 included spending at $214 million and 110.8 miles of main replacement in the EIRP for the 12 months ending September 30, 2024. The Company completed 126.1 miles of main replacement for $197.6 million and had facilities expenditures of $6 million, totaling $203.6 million for the 12 months ending September 30, 2024.

Q. What is the purpose of the Material Condition Non-Modeled Program?

A. The projects in the Material Condition Non-Modeled Program are Company-initiated replacements to address emergent issues that must be resolved to comply with regulations or to ensure public and/or employee safety, and to target certain assets which may not rank as highly in the Company's risk modeling but whose replacements offer operational advantages to the Company and customers. Projects include issues associated with:

(i) Emergent Replacements / Leak Mitigation (i.e. main or service replacements due to active gas main damages, leaks, or temporary repairs that need to be resolved within the year);

(ii) Safety situations (i.e. saddle tee replacements);

(iii) Cathodic issues (i.e. cathodic shorts and atmospheric corrosion);

(iv) Company-initiated work to resolve standards discrepancies or customer issues (i.e. obsolete fittings or materials); and

(v) Projects based on operational improvements that may not be represented effectively in risk model results (and therefore are not EIRP projects).

The combination of these items results in hundreds of small replacements annually that are emergent in nature. The Company's capital expenditures for this program were $38,516,000 in 2023 and are projected to be $38,256,000 for the year 2024; $36,358,000 for the 10 months ending October 31, 2025; and $56,206,000 for the test year 12 months ending October 31, 2026. The costs for the Material Condition Non-Modeled Program are set forth on Exhibit A-82 (KAP-4), line 2, and are further detailed later in this direct testimony. The increase in the capital expenditures for this program in the test year is due to the wrought iron replacement and HP waterway crossing initiatives described below which have projected expenditures of $5 million each in the test year. In addition, the program is increasing projected capital expenditures in Company-initiated work for leak mitigation at $4 million and 5,500 obsolete residential meter replacements at $3.7 million. Additional details on leaks and obsolete meters are included below in the Material Condition Renewals program. Projects completed under the Non-Modeled program are listed in the Non-Modeled program database and are designed by Distribution Engineering.

Projects that are initiated in the field and handled immediately by field personnel are included in the Material Condition Renewals program.

Q. What is the impact of the NGDP on the Material Condition Non-Modeled Program?

A. The objectives outlined in the NGDP moves the Company toward finalizing EIRP project areas earlier to complete design, and align with affected municipalities and stakeholders, increasing the overall timeline allowed for design and construction planning. While this is beneficial overall, and will positively impact the Company's EIRP, it reduces the flexibility of the EIRP to add projects to address emergent issues on the system. This approach allows for a balanced mix of EIRP and Non-Modeled work to continue with the long-term plan and address system issues as they arise. Therefore, the Company is expecting a sustained level of Material Condition Non-Modeled spending to address emergent issues for the test year. Even though vintage infrastructure is being replaced, what remains continues to deteriorate. In the long-term, enough vintage material will be replaced to allow for reductions in this program, but with the EIRP ending in 2035, the Company expects that reduction to occur beyond the test year in this case.

Q. Please describe the importance of replacing the Company's standard pressure system through projects in the Material Condition Non-Modeled Program.

A. The Company's standard pressure system, also called utilization or low-pressure system, is made up primarily of cast iron main. In most instances, cast iron main was installed from the early 1900s through the 1920s. Due to the vintage and the construction method used when the cast iron gas mains were installed, the joints between each segment of main will leak if the pressure is too high. These same connection points allow water to infiltrate the gas main when the pressures in the ground are higher than the pressure of the gas inside the gas main. This causes customer interruptions and other operating problems.

Within a standard pressure system, some meters have a regulator on them but not all do, meaning that if an overpressure situation were to occur on the gas main, there is not a device at each home or business preventing that higher pressure from reaching the customer's equipment. There are several areas of the state where there are very few miles of cast iron main remaining in that area or system. Replacing these sections allows the operating pressure in that entire area to be increased, ensuring that the benefits of the new system, such as improved safety and reliability, are equitably distributed across all communities, particularly those disproportionately affected by past infrastructure issues. Additionally, with elimination of the standard pressure system, each home or business will also now have a regulator installed, ensuring a consistent delivery pressure, and reducing the risk of higher pressures entering the premise. In 2023, the Company completed the elimination of the Plymouth cast iron system. This was the last cast iron system within the Livonia headquarter area. Eliminating this standard pressure system will ensure a higher level of reliability for the customers in the area. Customers will benefit from a higher level of reliability with no water infiltration, and improved safety due to regulated meters and elimination of these vintage, more leak-prone facilities.

Q. Are there additional standard pressure replacements in the Company's future plans for the Material Condition Non-Modeled Program?

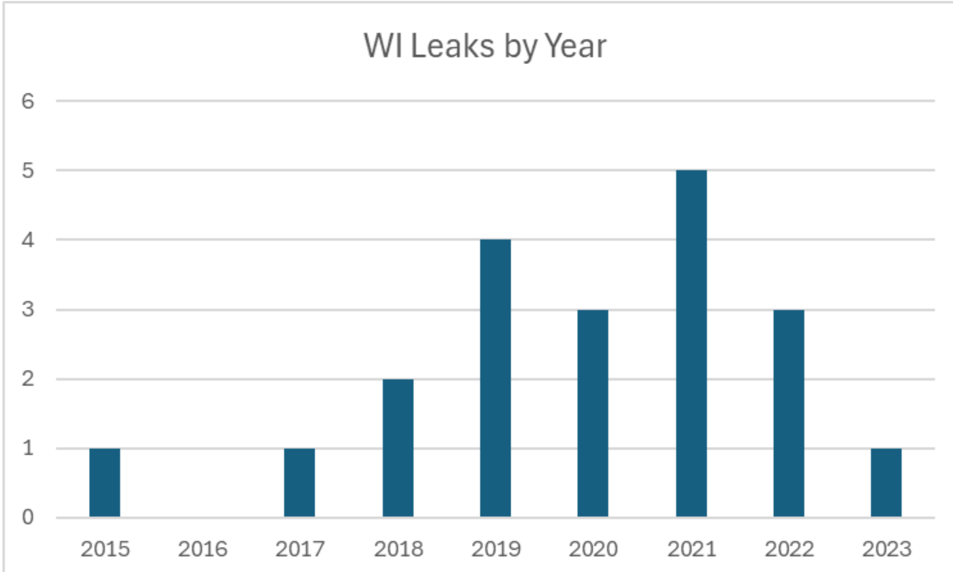
A. Not at this time, however, the Company will continue to evaluate risks across the gas system and prioritize as necessary, which may result in additional standard pressure replacement projects.

Q. Please describe the importance of replacing the Company's wrought iron gas main in the Material Condition Non-Modeled Program.

A. Wrought iron gas main was generally installed in the 1920s and 1930s. The annual DOT report combines cast iron and wrought iron together in a single line item, which indicates similar treatment and characteristics in the gas industry. Cast iron mains are only operated at low pressures, specifically less than 1 psig. Wrought iron mains, however, are part of the Company's medium pressure system, with MAOPs of up to 60 psig. Due to the way wrought iron was manufactured, its material properties are inconsistent and contains inclusions of lower quality materials. Therefore, it is not possible to choose a welding procedure that ensures the quality of the finished weld is adequate for use on the gas system. This leaves the Company with limited options for coupling or compression-style fittings when a leak or damage occurs on the wrought iron system, none of which are considered permanent repairs by the manufacturers of those fittings. The other alternative is replacement of the leaking main on an emergent basis.

Additionally, the Company experienced an increasing number of leaks on the wrought iron system in 2018 through 2022, which is impactful given the inability to make a permanent repair.

Figure 2: Wrought Iron Pipeline Leaks Found 2015 – 2023



With only 12 total miles of wrought iron left on the entire system, it is prudent to prioritize the replacement of these 12 miles and eliminate this issue from the system altogether. Most of this material (11 miles) is found in the smaller cities west and south of Kalamazoo, but there are small pockets in other areas of the state that make up the remaining mile. The Company plans to replace the wrought iron mains, and any intermingled other vintage material mains, under the Material Condition Non-Modeled Program over the next four years.

Q. Please describe the Line 1010 project in the Material Condition Non-Modeled Program.

A. Line 1010 is a 1950s era pipeline that was purchased by the Company from another utility. In 2020, PSHMA issued a rule adjustment to traceable, verifiable, and complete ("TVC") records for pressure test documentation. Pipeline segments installed prior to test record requirements implemented in 1970 were previously "grandfathered," or exempt, from original construction pressure test documentation requirements and allowed to operate at the highest actual operating pressure observed between 1965 and 1970. The updated 2020 rule limited this exemption to pipelines operating below 30% of the specified minimum yield strength (or “SMYS”). As a result, the Company must reconfirm the MAOP for all pre-1970 pipelines operating above 30% SMYS. Additional details on the PHMSA TVC compliance standards are included in the MAOP – Distribution projects section of Company witness Warriner’s testimony. The Line 1010 project is included in the Material Condition Non-Modeled program because it was started in 2021, prior to the establishment of the other MAOP projects discussed in the testimony of Company witness Warriner. The Company attempted to locate the original Line 1010 pressure test records, but when this line was built in 1951, there was no code requirement to maintain the records. The Company plans to replace sections of Line 1010, which will remove them from the TIMP cycle. Between 2021 and 2026, various segments of Line 1010 will be replaced or retired to establish a TVC record bringing this pipeline into compliance with the new PHMSA rule. The various projects will retire approximately 79,000 feet of existing main. The Company plans to install approximately 27,400 feet of new 12” steel HP main. The Company will also convert three services from high pressure to medium pressure. Additionally, the Company will install a 200-foot bypass near the Coolidge City Gate. The projected total cost to replace/retire the Line 1010 pipeline is $38,000,000, with $10,300,000 projected for 2024, $14,900,000 projected for 2025, and $12,800,000 projected for 2026. Any new main installed as part of this project section will not operate at a pressure that creates a hoop stress greater than 20% of the specified minimum yield strength of the pipe, meaning it will not need to be inspected every six years as part of TIMP. The decision to replace the pipeline was made after exploring the option to repressure test the existing pipeline. A cost and risk analysis were completed, and it was found 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 that is not reflected in the cost estimate 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 HP customers, each HP regulator stand. These customers would be without gas for the duration of the test prep, the actual test, and the reinstatement of that section of pipe. Test durations could vary from several hours to several days based on multiple factors including the length of pipe being tested and the type of testing required. Additionally, the testing would have to be performed in rolling segments, which would require additional work to be able to isolate individual test segments.

Q. Please describe the HP Waterway initiative in the Material Condition Non-Modeled Program.

A. On April 5, 2023, at approximately 9:30 pm, Consumers Energy customers experienced an interruption affecting approximately 4,500 customers around Hastings, MI. The cause of the interruption was a HP distribution gas main that broke where the pipeline crossed the Thornapple River. Although the pipeline was originally designed and installed in compliance with standards of the time, the flow of the river current appeared to have undermined the gas main, leaving it "elevated" in the waterway, with approximately 1.5 - 2 feet of open water between the pipe and the riverbed it was originally installed beneath. This elevated crossing allowed debris and water flow to exert unintended structural stresses on the pipeline, which led to an overload condition during flooding and caused a failure at a girth weld. An evaluation of the distribution system's GIS mapping overlayed with state hydrologic data, identified 442 total potential HP water crossings. Those 442 crossings have been evaluated by reviewing records and standards and performing field visits to validate/augment the data. The Company's risk models have been updated with the results and 15 additional pipe segments were identified as exposed or visible in a flowing waterway. A replacement plan has been created to remediate these over the next three years (2025-2027).

Q. Please describe the Material Condition Commercial/Industrial Meters Program.

A. The Material Condition Commercial/Industrial Meters Program includes the replacement of several commercial and industrial meter stands due to corrosion of the stand, obsolete regulation equipment, or excessive maintenance requirements. Replacement of obsolete equipment that the Company can no longer acquire parts for is prudent to ensure reliability for these large customers. Replacement of the stands that have excessive corrosion developing or excessive maintenance requirements is reasonable for both safety and reliability for that customer. These replacements are prioritized each year through collaboration between the Gas Commercial and Industrial Service team within Gas Operations, and the Metering and Regulation Engineering team within Gas Asset Management.

Q. Can you please explain the expenditures in the Material Condition Commercial/ Industrial Meters Program?

A. In 2023, $1,863,000 was spent to complete the Lansing Board of Water and Light project in addition to the replacement of four meter stands for other customers at a cost of $821,000. The projection is to replace nine stands in 2024 and thirteen additional in 2025. The Company's capital expenditures for this program were $2,684,000 in 2023 and are projected to be $1,300,000 for 2024; $1,634,000 for the 10 months ending October 31, 2025; and $2,391,000 for the test year 12 months ending October 31, 2026, respectively. The costs for the Material Condition Commercial/Industrial Meters Program are set forth on Exhibit A-82 (KAP-4), line 5.

Q. Can you explain the purpose of the Material Condition Renewals Program?

A. The Material Condition Renewals Program is part of a Company initiative to reduce actionable leaks through full-service replacement versus repair or reclassification of leaks. The distinction between the Material Condition Non-Modeled Program and the Material Condition Renewals Program is that the decision to renew the facility is done by field personnel on an immediate, emergent basis in the Material Condition Renewals Program. The program orders are created and completed in the field, are not contained within the Non-Modeled program database, and are directly related to active gas leaks on gas main and/or services. The capital expenditures for the Material Condition Renewals Program were $31,816,000 in 2023 and are projected to be $31,872,000 for 2024; $30,666,000 for the 10 months ending October 31, 2025; and $33,182,000 for the test year 12 months ending October 31, 2026, respectively. The historical and projected expenditures are detailed on Exhibit A-82 (KAP-4), line 3.

Q. Can you please explain the expenditures in the Material Condition Renewals Program?

A. The Material Condition Renewals Program focuses on addressing urgent issues that arise in the field, ensuring compliance with regulations and maintaining safety for both the public and employees. The capital expenditures, shown below in Table 8, in this program are allocated to projects that are initiated as a response to these emergent issues. The program is divided into four main areas:

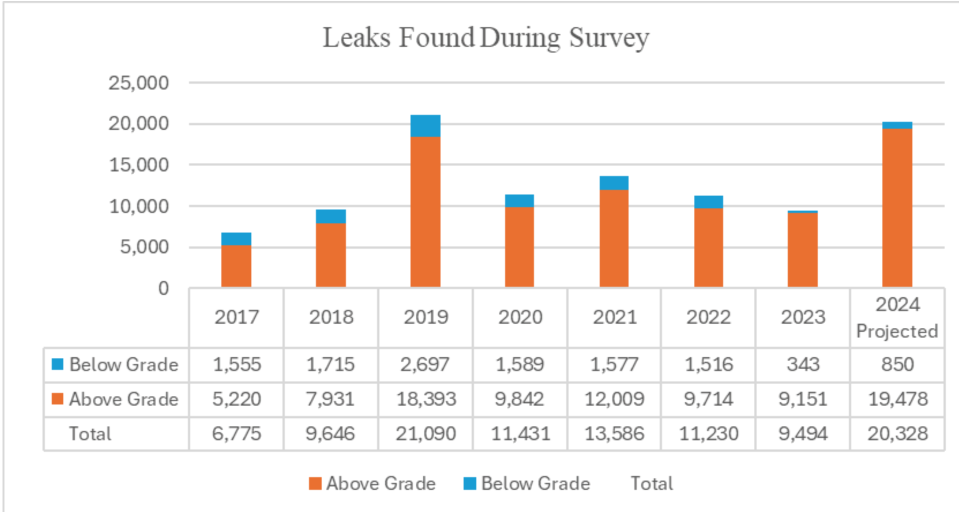
- Leak Renewals - Main: This involves replacing main pipelines that have developed leaks.
- Leak Renewals - Services: This covers the replacement of service lines that are leaking.
- Leak Renewals – Meter Stands: This area focuses on renewing meter stands that have leaks.
- Damages: This includes field-initiated repairs and replacements due to discovered damages.

Table 8: Material Condition Renewals Expenditures

($000)	Historical Year 12 Mos Ended 12/31/2023	Projected 12 Mos Ending 12/31/2024	Projected 10 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
Leak Renew Main	$ 7,157	$ 2,007	$ 3,679	$ 4,328
Leak Renew Service	$ 13,866	$ 15,170	$ 11,806	$ 13,889
Leak Renew Mtr/Stand	$ 1,745	$ 2,107	$ 1,015	$ 1,195
Damages	$ 9,047	$ 12,589	$ 14,165	$ 13,770
Total	**$ 31,816**	**$ 31,872**	**$ 30,666**	**$ 33,182**

Each of these areas ensures that the infrastructure remains safe and compliant with necessary regulations. Most new leaks are found during Leak Survey. Each year different sections of the system are inspected, which drives fluctuations in the number of leaks found annually. The historical and projected number of leaks found during Leak Survey is summarized in Figure 3.

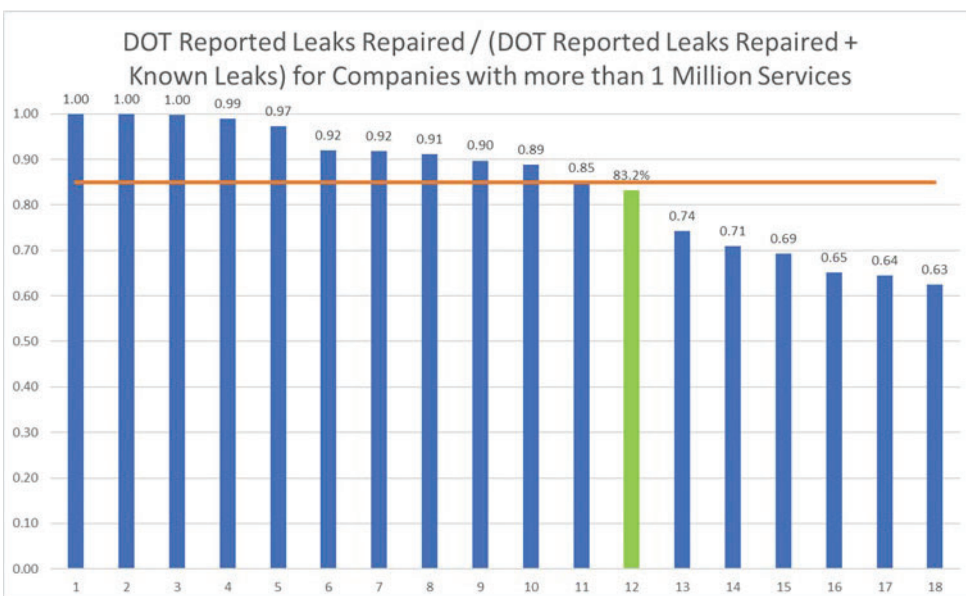
Figure 3: Total Number of Leaks Found During Leak Survey



	2017	2018	2019	2020	2021	2022	2023	2024 Projected
Below Grade	1,555	1,715	2,697	1,589	1,577	1,516	343	850
Above Grade	5,220	7,931	18,393	9,842	12,009	9,714	9,151	19,478
Total	6,775	9,646	21,090	11,431	13,586	11,230	9,494	20,328

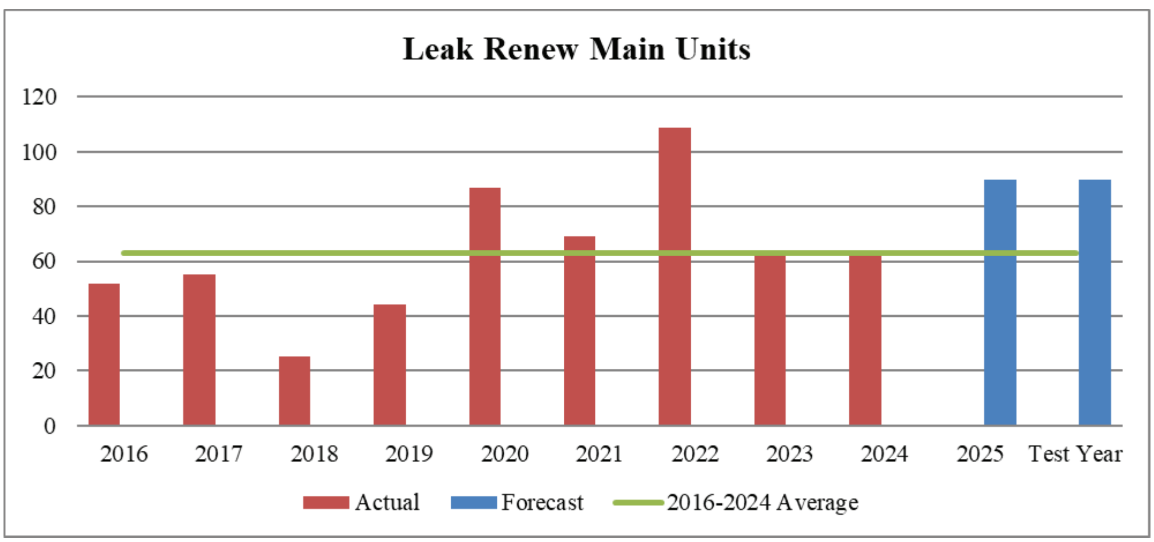
Additionally, Figure 4 below depicts a comparison of the percentage of leaks repaired for similarly sized gas companies, those with more than 1 million customers, and is based on the annual Federal DOT report information. This graph depicts the ratio of leaks repaired to the sum of leaks repaired and open leaks at year end for companies with vintage main as part of their system.

Figure 4: Industry Comparison of Leaks Repaired to Total Leaks



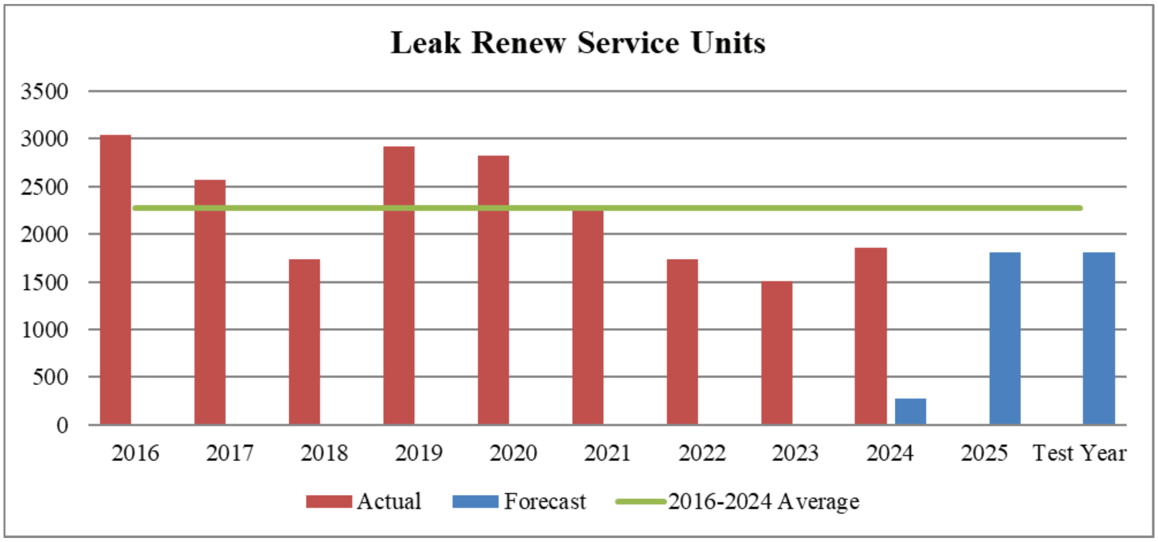
Consumers Energy is represented in green (column 12) and had a performance rate of 83.2% as of December 2023, which is below the industry average of 85%. Based on the benchmark data shown in Figure 4, the Company aims to reach the first quartile, which will enhance system integrity and public safety. To achieve this, the Company will continue to replace leaking metallic services and mains rather than repair them. This approach prevents future leaks on the same service or main and reduces methane emissions. This replacement work will reduce the number of leaks being managed by the Company at any given point in time, eliminating the need for repeat repairs on previously leaked services or mains. The Company plans to eliminate Grade 2 leaks by January 2026 and will continue to reduce Grade 3 leaks through the test year. Figures 5 through 7 illustrate the historical and projected unit counts for gas main, service, and meter stand replacements.

Figure 5: Gas Main Renewal Projects



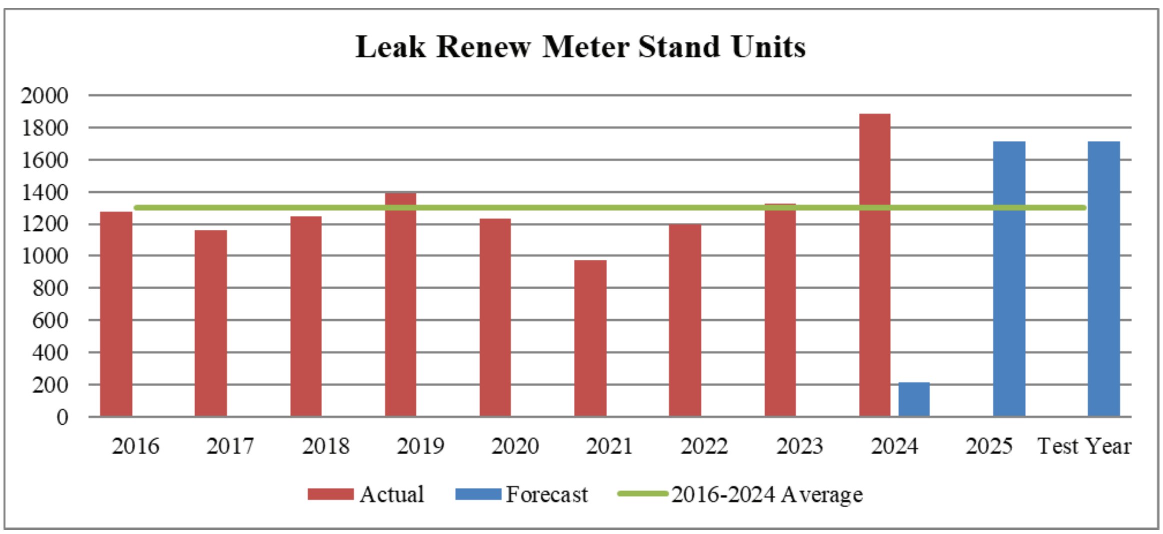
Leak Renew Main	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Test Year
Actual	52	55	25	44	87	69	109	62	62		
Projected										90	90
Actual Cost ($000)	$ 930	$1,119	$ 377	$2,405	$5,590	$4,522	$3,065	$7,157	$2,007		
Projected Cost ($000)										$4,328	$ 4,328

Figure 6: Gas Service Renewal Projects



Leak Renew Service	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Test Year
Actual	3,043	2,571	1,740	2,918	2,824	2,302	1,732	1,512	1,859		
Projected									270	2,030	2,030
Actual Cost ($000)	$ 11,765	$ 11,250	$ 10,226	$ 19,657	$ 22,788	$ 21,537	$ 16,040	$ 13,866			
Projected Cost ($000)									$ 15,170	$ 13,889	$ 13,889

Figure 7: Gas Meter Stand Renewal Projects



Leak Renew Mtr/Stand	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Test Year
Actual	1,274	1,163	1,246	1,393	1,231	974	1,195	1,325	1,881		
Projected									216	1,715	1,715
Actual Cost ($000)	$ 334	$ 349	$ 474	$ 723	$ 788	$ 740	$ 1,027	$ 1,745			
Projected Cost ($000)									$ 2,107	$ 1,195	$ 1,195

This program includes funding within the Damages category to replace obsolete regulated meter stands. The Customer Metering section of the NGDP explains that the sole-sourced

Regulated Meter ("RM") residential gas meter was discontinued in 2021. This meter type is the most common in Consumers Energy's gas system. As the Company's RM inventory decreases, it will be necessary to replace RM meter stands with industry-standard top-connect meter stands due to the different connection methods of each type of meter. These new stands will feature a temperature-compensated top-connect gas meter and a separate pressure regulator. To meet meter exchange requirements and minimize extended customer outages during emergent meter exchanges, the Company will continue converting meter stands in 2024. The projected cost for rebuilding 20,000 meter stands is $12 million.

Q. Please describe the anticipated requirements to comply with Leak Detection and Repair regulations ("LDAR").

A. The Company is reviewing a PHMSA Notice of Proposed Rule Making ("NPRM") issued on May 4, 2023, titled Gas Pipeline Leak Detection and Repair[1]. The publication outlines proposed revisions to numerous rules in the Minimum Federal Safety Standards for Pipelines, including Rule 192.723 and Rule 192.763 requirements for advanced leak detection equipment, enhanced leak detection practices, increased leak survey frequency, and defined repair timing for all leaks, which could increase spending in the future. Additional information on the proposed rulemaking is included in the direct testimony of Company witness Pnacek. The Company expects the rule to be published by January 2025,

[1] PHMSA NPRM on Gas Pipeline Leak Detection and Repair publication: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-05/Gas%20Pipeline%20Leak%20Detection%20and%20Repair%20NPRM%20-%20May%202023.pdf

with an anticipated effective date six months later. Full compliance with these requirements is expected in January 2028.

Q. Please describe PHMSA's LDAR requirements the Company is expecting to be required to comply with during the test year.

A. For grade 2 leaks known to exist on or before July 2025, repairs must be completed within one year from the publication of the final rule, expected by January 2026. For grade 3 leaks known to exist on or before the effective date of the rule, repairs must be completed within three years from the publication of the final rule, expected by January 2028. In addition, for gas transmission, any leak in High Consequence Area ("HCA"), Class 3, or Class 4 location known to exist by the effective date of this rule, repairs must be completed within one year from the publication of the final rule, expected by January 2026.

Q. Please describe the Company's plan to comply with the Leak Backlog requirements of the proposed rule?

A. The Company is aware of the compliance timeline proposed for this regulation but is not requesting full compliance funding for capital expenditures related to the LDAR rule in this case. The Company is seeking funding to address the known leak elimination requirements of the rule. This is due to the benefits to public safety and the desire to reduce risk. The Company plans to eliminate the backlog of known leaks at an accelerated rate, regardless of when the LDAR rule is published. An additional $1,510,000 in capital expenditures is included in this case to address the anticipated leak backlog for the test year. Since the Final Rule has not yet been published and substantive changes could affect these projected expenditures, the Company is requesting the Commission approve the ability to defer any test year revenue requirement of capital expenditures resulting from the final rule that exceed the requested funding in this case. The regulation is anticipated to be published shortly after this case filing.

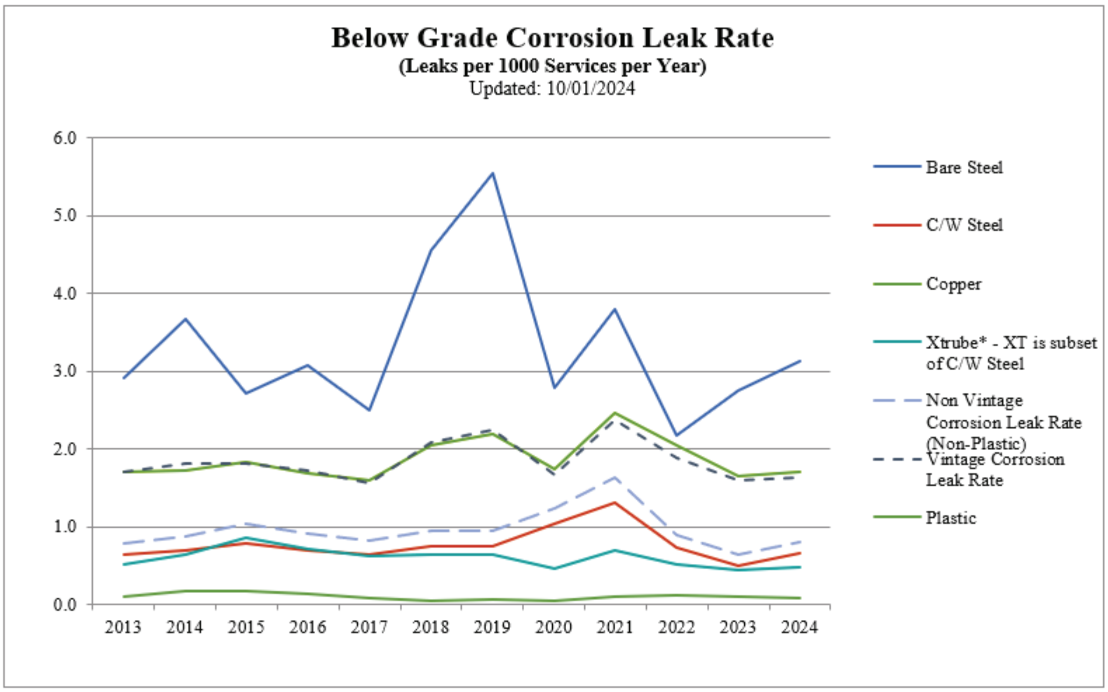
Q. What impact does the NGDP have on the Material Condition Renewals Program?

A. As outlined above, the Company is targeting the replacement of leaking facilities through the Material Condition Renewals Program to ensure a safe and reliable gas system. These efforts, combined with the planned replacement of vintage facilities through the NGDP, Asset Relocation – Civic Improvement, and other Material Condition programs will result in a reduction in the number of leaks on the Company's system, leading to a reduction of methane emissions and an improvement to public safety. Replacing these facilities when responding to the leak that has occurred prevents a return trip for future additional leaks on the same vintage facility and works in conjunction with the goals of the NGDP to eliminate vintage materials. Facilities replaced under the Material Condition Renewals Program will not need to be replaced again through the EIRP or VSR Program. As stated above, in relation to other programs, the Company needs to achieve a sufficient level of replacement before the number of leaks found is expected to decrease. As more vintage facilities are replaced, the Company expects to be able to reduce expenditures in the Material Condition Renewals Program as well.

Q. Please describe the VSR Program.

A. The VSR Program began in 2017 and is a comprehensive approach to replacing all the Company's copper and bare steel vintage service materials, along with services for which the material type is unknown. The Company's goal is to programmatically replace all these service pipe types not replaced under the EIRP Distribution, Material Condition Renewals, Material Condition Non-Modeled, and Asset Relocation programs. These vintage service materials have a higher corrosion leak rate than current materials. Copper services make up approximately 85.4% of all vintage services. Figure 8 below demonstrates the corrosion leak rate on bare steel and copper services, compared to that of coated and wrapped steel and Xtrube steel services, as well as the average leak rate for vintage and non-vintage services:

Figure 8: Below Grade Corrosion Leak Rate (As of 10/1/2024)



Q. Should the duration of the VSR Program be aligned with the timeline of the EIRP?

A. There are operational advantages to aligning the VSR Program timeline with the EIRP, as discussed further below. Aligning the overall program duration with the EIRP also allows the Company to exclude any services that are on a vintage (EIRP-type) gas main in the proactive VSR Program, because those services will be replaced when the EIRP replaces the gas main. To prioritize replacement within this timeframe, the Company will target those services outlined below with the highest potential for future leaks. The Company will continue to monitor leak, age, and soil information and will adjust future vintage service replacement plans if the data demonstrates additional trends.

The VSR Program classifies vintage services into four categories- “In-Grid VSR,” “Proactive In-Grid VSR,” “Proactive Out-of-Grid VSR,” and “Other Programs.” When a vintage service is connected to a vintage EIRP main gas distribution pipe that is being replaced, and construction crews working on the EIRP project upgrade the service(s) along with the main, the program classifies these services as In-Grid VSRs. The VSR Program proactively replaces vintage services that are not included as part of a gas distribution main pipe replacement. When these vintage material services are replaced within an EIRP project geographic footprint, they are known as Proactive-In Grid VSRs. When these vintage material services are located outside of the planned geographic footprint of an EIRP project and the service replacement is not completed with a gas distribution main pipe replacement, they are known as Proactive Out-of-Grid VSRs. Vintage services are also replaced through other programs, including Material Condition Renewals, Material Condition Non-Modeled, Asset Relocation programs, and others. These vintage service replacements are classified as Other Programs.

Q. How does the Company determine the order in which proactive vintage services will be replaced?

A. Risk and location are the primary factors that determine prioritization. For VSRs selected through 2024, the Company used a manual analysis process that examines the leak rate along with other factors such as soil conditions and material age, of each distribution service material to prioritize replacement in accordance with the Company’s DIMP. Starting with 2025 VSRs, the Company has transitioned from the manual process to running the analysis in the Distribution Risk Analysis Model ("DRAM"). The DRAM was implemented in 2019, and is used primarily to analyze distribution pipelines, which supports the identification of EIRP projects. The Company has gained enough experience using the DRAM to apply the model to services as well. This aligns our approach to an industry standard model and will create efficiency within our engineering team.

Q. Does the approach for prioritizing EIRP work impact the selection process for vintage services?

A. The EIRP approach plans for the replacement of all vintage services within the EIRP project's geographic footprint, allowing the Company to gain efficiency in the field. This approach enables the Company to eliminate all vintage distribution facilities in the project footprint in one trip, which reduces impacts to customers and municipalities. However, not all vintage services fall within an EIRP project where there is vintage main, and thus the Company still requires a risk-based selection process to prioritize these services.

For 2025 and 2026, the Company plans to replace 7,366 and 8,535 total vintage services, respectively. A breakdown of these services is described below.

- In-Grid: The Company's forecast includes the replacement of 2,672 vintage services in 2025 and 2,122 vintage services in 2026 from In-Grid as part of the EIRP project work. The costs of these VSRs will be charged to the EIRP Program.

- Proactive In-Grid: The Company will also proactively replace vintage services within the projects targeted by the EIRP that are not connected to a vintage main pipeline. These projects will be selected for replacement based on the risk associated with the gas main in that area, but once a project is selected, all vintage facilities in that area will be replaced. For 2025 and 2026, the Company expects the selected EIRP projects to contain approximately 994 and 1,413 proactive vintage services, respectively. As these services are not connected to a vintage main, the costs for these VSRs will be charged to the VSR Program.

- Proactive Out-of-Grid: For 2025 and 2026, there are a total of 3,200 and 4,500 vintage services, respectively, that do not fall within an EIRP project, and therefore would not be prioritized in the EIRP. The costs for these VSRs will be charged to the VSR Program.

- Other Programs: For 2025 and 2026, the Company is forecasting 500 vintage service replacements each year from Other Programs.

Q. How many services will be replaced under the VSR Program?

A. As of December 31, 2023, the Company has removed approximately 69,000 vintage services. At the start of 2024 there were 112,157 vintage services remaining on the Consumers Energy gas system. Table 9 below outlines the actual vintage services replacement figures as well as the projections for 2024, 2025, and 2026, including the test year.

The Company will continue to replace vintage services as part of EIRP Distribution, Material Condition Renewals, Material Condition Non-Modeled, and Asset Relocation programs. This combined approach will continue to eliminate the highest risk services on the Company's distribution system, which increases safety for customers and the public. Additionally, eliminating the highest risk vintage services will reduce the number of future gas leaks on those services and reduce greenhouse gas emissions. This approach is consistent with the Company's DIMP plan, and per that plan, will be monitored regularly for effectiveness.

Table 9: Vintage Services Replacements

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Projected 2024	Projected 2025	Projected 2026	Projected 12 Mos Ending 10/31/2026
VSR Program Units	6,307	9,381	5,571	5,456	5,056	2,176	1,228	2,875	4,194	5,913	5,827
VSR Unit Cost	$5,322	$6,037	$7,260	$7,848	$6,518	$7,888	$9,246	$6,493	$6,671	$7,389	$7,296
VSR Program Spend ($000)	$33,564	$56,634	$40,443	$42,818	$32,955	$17,165	$11,354	$18,666	$27,978	$43,689	$42,513
EIRP/Other Programs	5,169	4,042	4,064	4,291	5,245	8,235	3,576	3,476	3,172	2,622	2,677
Total Services Replaced	11,476	13,423	9,635	9,747	10,301	10,411	4,804	6,351	7,366	8,535	8,504
Total Services Remaining	170,478	157,055	147,420	137,673	127,372	116,961	112,157	105,806	98,440	89,905	81,401

The capital expenditures for the VSR Program were $11,354,000 in 2023 and are projected to be $18,666,000 for 2024; $25,885,000 for the 10 months ending October 31, 2025; and $42,513,000 for the test year 12 months ending October 31, 2026, respectively. The historical and projected expenditures are detailed on Exhibit A-82 (KAP-4), line 4.

Q. Does the replacement of aging pipeline facilities through the Material Condition programs have the potential to reduce emissions into the atmosphere?

A. Yes. By replacing aging materials with the potential for increased leak rates, the Company is reducing the future methane emissions into the atmosphere.

2. <u>Gas Operations Other</u>

Q. Please list the programs within Gas Operations Other capital expenditures.

A. The five programs, as shown on Exhibit A-83 (KAP-5), page 1, are:

- Routine Computer and Equipment;
- Tools;
- Land and Right of Way ("ROW");
- Compliance and Controls; and
- Geospatial Inventory and Modeling Program.

Q. Please describe the capital expenditures relating to the Gas Operations Other Program as shown on Exhibit A-12 (KAP-3), Schedule B-5.8, line 2.

A. The Gas Operations Other Program expenditures were $7,750,000 for the year 2023; and are projected to be $16,094,000 for 2024; 11,943,000 for the 10 months ending October 31, 2025; and $17,090,000 for the test year ending October 31, 2026, as set forth on Exhibit A-12 (KAP-3), Schedule B-5.8, line 2, columns (b), (c), (d), and (f), respectively. The Gas Operations Other Program includes the following programs:

- Routine Computer and Equipment: Computer equipment includes printers, plotters, and other technical equipment. Desktop and laptop computers for existing employees are not included in this program as they are purchased through the Information Technology ("IT") department.
    - The Routine Computer and Equipment Program expenditures were $300,000 for the year 2023; and are projected to be $50,000 for 2024; $5,000 for the 10 months ending October 31, 2025; and $50,000 for the test year ending October 31, 2026, as detailed on Exhibit A-83 (KAP-5), line 1.
- Tools: Tools for field employees are purchased as part of this program. The purchase of new tools will replace tools that are worn, broken, or outdated. Tools purchased due to safety issues that come up throughout the year that meet capitalization criteria are also part of this program. The program also includes ergonomic tools that will prevent or lower the risk of employee injury.
    - As described in the Material Condition Renewals Program section earlier in my testimony, the PHMSA issued NPRM – Gas Pipeline Leak Detection and Repair which proposes new Rule 192.763 to require that leak surveys be performed using advanced technology and practices consistent with the proposed Advanced Leak Detection Program ("ALDP") performance standard. The proposed new rule will impact the leak detection tools purchased for employees when implemented, which the Company expects will occur within the test year of this case. However, since full compliance with the LDAR requirements is expected in January 2028, the Company has not included additional tool costs for complying with the new rule in this case.
    - The Tools program expenditures were $5,613,000 for the year 2023; and are projected to be $4,510,000 for 2024; $2,472,000 for the ten months ending October 31, 2025; and $4,510,000 for the test year ending October 31, 2026, as detailed on Exhibit A-83 (KAP-5), line 2.

- Land and ROW: This program includes costs associated with Land and ROW specialists supporting gas distribution projects. The Land and ROW program expenditures were $1,622,000 for the year 2023; and are projected to be $831,000 for 2024; $701,000 for the 10 months ending October 31, 2025; and $849,000 for the test year ending October 31, 2026, as detailed on Exhibit A-83 (KAP-5), line 3.

- Compliance and Controls Projects: These investments are made up of four projects as listed in Table 10 below. The Compliance and Controls program expenditures were $214,000 for the year 2023; and are projected to be $4,875,000 for 2024; $447,000 for the 10 months ending October 31, 2025; and $4,168,000 for the test year ending October 31, 2026, as detailed on Exhibit A-83 (KAP-5), line 4.

- Geospatial Inventory and Modeling Program: I will further describe this program later in my testimony. The description of how the projections were developed for this program are included in the O&M section of my testimony. The Geospatial Inventory and Modeling program expenditures were $0 for the year 2023; and are projected to be $5,828,000 for 2024; $8,319,000 for the 10 months ending October 31, 2025; and $7,513,000 for the test year ending October 31, 2026, as detailed on Exhibit A-83 (KAP-5), line 5.

Q. Please describe the capital projections for the Compliance and Controls projects.

A. These investments are made up of five projects with the capital projections as listed in Table 10 below.

Table 10: Compliance and Controls Project Detail

($000)	2023 Actual	2024 Projected	2025 Projected	2026 Projected	12 months ending 10/2026
Advanced Methane Detection	$0	$4,650	$265	$3,181	$3,181
Enterprise Contractor Oversight Dashboard	$21	$3	$15	$0	$0
Enterprise Corrective Action Plan - Gas	$49	$204	$200	$0	$33
Damage Prevention and MISS DIG	$59	$18	$0	$954	$954
Other	$86	$0	$0	$0	$0
Total Compliance and Controls	**$214**	**$4,875**	**$480**	**$4,135**	**$4,168**

Q. Please describe Advanced Methane Detection.

A. AMD is technology designed to identify methane leaks with exceptional precision. Unlike traditional leak detection equipment that measures methane in parts per million (ppm), AMD can detect methane in parts per billion (ppb). This heightened sensitivity allows for the identification of even the smallest leaks. Additionally, AMD technology offers several advanced features including:

- Emission Rates: AMD can measure the rate at which methane is being emitted.
- Breadcrumbing: This feature helps in tracking the path of methane emissions.
- Geospatial Locations: AMD provides precise geospatial data of potential methane indications.
- Time-Stamped Datalogging: All data is logged with timestamps, providing a detailed record of methane emissions over time.

These capabilities make AMD a powerful tool for monitoring and managing methane emissions more effectively than traditional methods.

Q. How will this technology improve the Company's capability to find leaks on the system?

A. This technology enables the Company to find and prioritize the higher risk leaks to improve public safety. Leveraging risk-based prioritization and algorithms, the Company has implemented a Super Emitter Program, which identifies the largest methane emitting leaks on its gas distribution system for investigation and escalated remediation. AMD is also proving to be seven times more effective at locating below ground leaks, leading to enhanced public safety.

Q. Please explain the benefit to the customer delivered through the AMD.

A. AMD offers several key benefits to customers including:

- Enhanced Safety: By improving the Company's ability to detect and pinpoint leaks more accurately, AMD helps prioritize the remediation of high-risk leaks. This leads to a safer environment for customers.
- Risk-based Prioritization: The addition of emissions rate data allows the Company to assess and address leaks based on their potential risk, ensuring that the most significant leaks are dealt with first.

- Increased Detection Sensitivity: With its heightened sensitivity, AMD can detect methane emissions more effectively, leading to better classification and remediation of leaks.

- Support for Environmental Goals: AMD aids the Company in its goal of achieving net zero methane emissions by identifying and quantifying large emission sources. This enables targeted and efficient remediation efforts.

Overall, AMD enhances the Company's ability to manage methane emissions, contributing to improved public safety and environmental sustainability.

Q. What solution is the Company implementing?

A. The Company is currently using a third-party vendor to develop its AMD capabilities. This decision was made after careful consideration of industry offerings, and peer-to-peer conversations and communications with utilities across the United States. The vendor is known as an industry leader in Ring-Down Spectroscopy and has many years of experience deploying this technology to solve gas utility problems, such as leak survey and emission quantification. This expertise has assisted the Company's deployment of AMD in a thoughtful and progressive way to lower risk and increase safety for customers.

Q. Did the Company consider other industry offerings and equipment for comparison and testing of outputs?

A. Yes, other options were evaluated for both capabilities and costs. The Company evaluated an option that it ultimately eliminated due to the cost of that solution exceeding the estimated cost to operate the selected units, which are installed in vehicles dedicated to methane detection. Another option that detects methane and ethane using a "Middle InfraRed Analyzer" instead of a "Ring-Down" sensor was not selected as it was newer to the market and there was little industry information available, particularly for large-scale implementation. The Company will periodically review the industry and market for AMD best practices and technologies.

Q. How is Consumers Energy planning on implementing this technology?

A. Consumers Energy planned a two-phased AMD implementation, with methane emission, risk modeling, and super emitter work activities planned as part of Phase 1. Phase 2 of the AMD technology implementation looks to use AMD for compliance-based leak survey, and as a result of the higher quality data, analytics and algorithms can modernize and enable risk-based leak surveys. This phase will be supported by the GCCP - SIMS Conversion project described in the Geospatial Inventory and Modeling section later in my testimony.

Q. Please explain the learnings from Phase 1.

A. The Company conducted several case studies during Phase 1 to learn the technology and identify areas of value beyond compliance leak survey. Below are learnings from these studies.

- **Emission Quantification:** Emissions Quantification is a drive mode that is used to measure emissions based on the flow rate of indications to quantify distribution system methane emissions as well as individual indications. In 2024, the Company will survey 50% of the gas distribution system to measure emissions and plans to survey 100% of the gas distribution system annually starting in 2025.

- **Source Discrimination:** It was determined that source discriminations work with AMD devices to assist in pinpointing hard-to-locate leaks or to rule out bio-gas methane that could produce false positives through current leak survey methodologies.

- **Pre/Post Construction drives:** The Company was able to drive pre-construction collecting data to determine the emissions being released and then drive again after construction to determine whether the replacement projects reduced emissions.

- **Super Emitter Survey:** While surveying in Emissions Quantification mode (explained above), the Company identifies specific indications with high flow rates, called super emitters. Most recently, in 2024, Consumers Energy is specifically targeting indications with flow rates at 30 standard cubic feet per hour (SCFH) or greater. These indications are investigated and, if confirmed, escalated for remediation regardless of the leak survey schedule. In the Company's studies, it was determined that Super emitters account for only 1.8% of the indications detected, but account for 17.6% of the total emissions.

Q. Please explain the transition from Phase 1 to Phase 2.

A. In addition to the Phase 1 studies cited above, compliance leak survey testing was performed in parallel with current methodologies to prepare for Phase 2, and to determine differences in output and quality, while also identifying needed changes in standards and practices for future implementation. Traditional leak survey inspectors walked each location as the unit drove the same area, followed up by investigation of any suspected leaks, and then compared the data. On average, AMD found one indicator of a possible leak for every mile of distribution main investigated. In 2023, the Company entered Phase 2 to further develop AMD capabilities for performing compliance leak survey. In this phase, the Company will continue to refine its detection capabilities with more parallel testing and procedure refinement through 2024 to ensure it is focusing its investigations on true gradable leaks. The new AMD application hardware and software will be complemented by current asset management, work management, and analytics platforms - including the GIS; Inspection Manager; Systems, Applications, and Products ("SAP"); Service Suite; and Distribution Risk Analysis Model.

Q. Please further explain the planned implementation for Phase 2.

A. In 2023, AMD was used to inspect sections that were due for compliance while traditional leak survey inspectors continued their normal walking survey to get a baseline. In 2024, AMD procedures were refined and adjusted to scale up its use for compliance leak survey implementation. Other supporting technology projects will also be developed. The goal is to operationalize AMD more fully. A full-scale rollout is planned for 2026, where AMD will become the primary method for compliance leak surveys. The Company is transitioning from an asset-based to a grid-based leak survey program. This change will enable AMD to efficiently scale compliance leak surveys by coordinating all distribution asset surveys within a specific area simultaneously. This transition project is slated to begin in the 2025 compliance leak survey season. Traditional leak survey will be used for those areas not part of the AMD schedule in these years to fulfill any compliance leak survey requirements. Additionally, the Company will continue the Phase 1 emission surveys, super emitter, and pre-post construction surveys. This approach aims to enhance the efficiency and effectiveness of leak detection and compliance surveys, leveraging AMD's advanced capabilities.

Q. How will the Company's procedures be updated when a potential leak is found by AMD?

A. Leak indications are generated by the AMD technology after multiple nights of surveying each asset in a survey area, usually over three separate nights, which is the recommended number of drives to ensure comprehensive coverage. The collected data is sent for analysis and at the conclusion of the final drive, the leak detection team generates reports and schedules investigations. Qualified individuals will then walk all mains and services, including meter sets, within and 50 feet beyond the AMD-generated search area to investigate the potential leaks. If leaks are found, the qualified investigator follows existing leak response and reporting guidelines to address and document the issue.

Q. What costs are associated with Phase 1 testing and Phase 2 rollout?

A. Table 11 below provides the capital investment and O&M expenses for the AMD Program. The 2021 and 2022 actual amounts were for Phase 1 units and testing. The 2024 capital costs are associated with the purchase of three additional units. The O&M expenses will continue to be license fees and costs associated with performing AMD surveys and studies.

Table 11: AMD Actual and Projected Costs

	2021 Actual	2022 Actual	2023 Actual	2024 Projected	2025 Projected	2026 Projected	Total
O&M	$122,874	$102,706	$188,561	$452,204	$572,508	$572,508	$2,011,361
Capital	$2,400,000	$4,635,000	$-	$4,650,000	$265,000	$3,181,000	$15,131,000

Q. Is the Company expecting to see an increase in leaks and associated leak repairs using this new technology?

A. Yes, the Company does anticipate an increase in the detection and repair of leaks with the implementation of AMD technology. AMD has proven to be seven times more effective at finding below ground leaks and 5% more effective at detecting above ground leaks compared to traditional methods. The technology's heightened sensitivity allows for more precise detection of potential leaks. By providing exact search areas, AMD minimizes the chances of human error during leak detection. These improvements mean that more leaks are likely to be identified and repaired, enhancing overall safety and system integrity. However, it is important to note that these results are based on a limited sample size and may evolve as the program expands into compliance leak surveys.

Q. Does Consumers Energy's AMD deployment support any regulatory requirements not already discussed?

A. Yes. The PHMSA Advisory Bulletin 2021-0050 requires pipeline facility operators to update their inspection and maintenance plans to address the elimination of hazardous leaks and minimization of releases of natural gas. Additionally, as described in the Material Condition Renewals Program section earlier in my testimony, PHMSA issued NPRM – Gas Pipeline Leak Detection and Repair which proposed new Rule 192.763 to require that leak surveys be performed using advanced technology and practices consistent with the proposed ALDP performance standard. The Company is currently reviewing the proposed new rule and expects it to be issued within the test year of this case. The Company has built its AMD Program to further its leak and methane detecting capabilities in accordance with this and other laws, codes, and guidelines. Regardless of regulations, the Company is committed to its AMD program due to the clear public safety and emissions reduction benefits.

Q. Please describe how the implementation of AMD impacts Consumers Energy's stated goals in the NGDP.

A. AMD is described in the NGDP under the technology investments and supports the Company's stated goal to provide a safe, affordable, reliable, and clean natural gas system for Michigan. The implementation of this technology also supports the Company's GSMS as it is part of the recommended practice to evaluate new platforms that can further enhance the Company's capabilities in alignment with API RP 1173, which provides, "11.2 – *Management shall also periodically evaluate new technology that may enhance pipeline safety*."

Q. Please describe the Enterprise Corrective Action Program.

A. The ECAP was initiated at Consumers Energy in 2020 as an enterprise-wide issue management and compliance program supporting safe and excellent operations. The structured platform and methodology allow for transparency in reporting issues, identifying trends, and closing compliance and safety gaps through corrective actions and controls, based upon associated risk thresholds. ECAP's functionality for managing processes and performance, as well as analyzing data, focuses risk reduction efforts, informs operational business decisions, and promotes the integrity and deliverability of the energy infrastructure. Starting in 2022, ECAP supported stakeholders in Gas Operations, Engineering, and Regulatory maintaining adherence to GSMS standards established in API RP 1173.

Q. What costs are associated with the ECAP implementation?

A. ECAP will use a phased implementation approach:

- Phase 1 (Go Live 2022) – Gas Operations, Regulatory, and Engineering;
- Phase 2 (Go Live 2023) – Electric Operations and Engineering;
- Phase 3 (Go Live 2024) – Generation Operations and Electric Supply Engineering; and
- Phase 4 (Go Live 2025) – Corporate Safety and Health (Gas, Electric, and Generation).

The actual and projected capital expenditures included in this case represent the gas portion of ECAP only.

Table 12: ECAP Actual and Projected Capital Costs

2021 Actual	$ 1,226,304	Vendor software to acquire licensing, service, and project support to implement ECAPs system of record into the Enterprise
2022 Actual	$ 1,204,618	ECAP expense was $126,333 for the closeout of Phase 1 project implementation. Additionally, $1,078,285 was expensed in the Computer and Equipment program to advance the purchase of the Environmental Health and Safety Suite of software related to Phase 4 of the project.
2023 Actual	$ 48,971	Statement of work execution for the Phase 4 project of ECAP in 2024
2024 Projected	$ 204,000	Projected expenses for ECAP platform modifications to support Phase 4
2025 Projected	$ 200,000	Projected expenses for ECAP project closeout

Q. Please describe the Irth Solutions software within Damage Prevention and Miss DIG.

A. The Irth Solutions software is a damage prevention and 811 ticket management solution used by the Company to report and document daily ticket volume and response as well as field proactive and re-active work.

Q. Please describe the Irth Software funding requirements.

A. The Irth software subscription includes Utilisphere fixed subscription fees, as well as additional features such as photo artificial intelligence ("AI") and augmented reality ("AR"). This software leverages the latest technology to ensure the safety, resiliency, and reliability of critical network infrastructure. The projected funding will cover the next 5-year subscription term from 2026 to 2030. This includes:

- Utilisphere fixed subscription fees;
- Annual 100,000 additional tickets;
- New capabilities of photo AI for staking and locating audits, supporting quality assurance; and
- New capabilities of AR to enable visual field representation of underground assets, aiding Damage Prevention field activities and quality assurance processes.

The total expenditure for the 5-year subscription term is $1.6 million. Based on ticket volume, the gas portion of this expenditure is $954,000.

Q. Please highlight the benefits of the Irth software.

A. The Irth software provides the following benefits:

- Provides analytics and reporting on ticket volume, responses, and timeliness.
- Provides a calculating risk analysis on each excavator working near Company facilities which maximizes team effectiveness.
- Tracks and records all program work being completed by field teams.

- Acts as a backup ticket management solution supporting the timeliness procedure.
- The addition of photo AI and AR functionality to further increase the Company's ability to maximize productivity.
- Supports the Company's overall damage prevention and public safety program.

Q. Please describe the GCCP – SIMS project funding requirements within the Geospatial Inventory and Modeling Program.

A. The GCCP – SIMS project will convert and migrate the SIMS gas service asset data into the gas distribution GIS and reconfigure application and technical integrations, creating a single system of record for both gas service and distribution asset records. This program includes O&M and capital funding requirements as shown in Table 13 and is projecting project completion in late 2024/early 2025. There are no O&M or capital funding requirements for GCCP-SIMS in the test year for this case.

Table 13: GCCP - SIMS Actual and Projected Costs

GCCP-SIMS								
	2017 - 2021 Actual	2022 Actual	2023 Actual	2024 Projected	2025 Projected	2026 Projected	Project Total	Test Year
O&M	$ 1,808,185	$ 564,455	$ 2,306,199	$ 3,134,724	$ -	$ -	$ 7,813,563	$ -
Capital	$ 3,345,625	$ -	$ -	$ 2,939,740	$ -	$ -	$ 6,285,365	$ -

The existing gas service records have no spatial data, and the database is limited in its ability to store all required service attributes, which create inaccuracies in U.S. DOT reporting, System Planning gas load analysis, and Distribution Risk Models. Tabular data is manually linked between the SIMS and the GIS, which causes incomplete and inconsistent data. Gas data must be queried from two independent systems and pieced together to get a complete picture of the distribution network, which limits the Company's ability for data analytics, creates operational complexities, adds risk to damage prevention efforts, and increases response time during safety emergencies. The existing systems use vastly different data formats and technologies for maintaining and accessing this data, therefore creating two overlapping and sometimes conflicting systems of record. The project will provide value by:

(1) Establishing a single gas distribution system of record within GIS that represents the gas distribution main and services from the customer's meter stand to the city gate;

(2) Creating an enhanced GIS connectivity model with spatial placement of gas services over an ortho-photo grid, which is essentially digital imagery of an aerial photograph;

(3) Improving the ability to identify data gaps and inconsistencies systematically;

(4) Strengthening the data required to support advanced risk analysis; and

(5) Creating the foundation required to enable future asset maintenance tools, including tools that allow the Company to track gas distribution assets, and to develop GPS leak survey routes to facilities.

Without this support, there is increased safety risk associated with the inability to provide accurate and real-time data to end users to support planned and emergent operational activities, incident response, and predictive analysis that requires more accurate data analytics to support compliance reports.

Q. Please describe the Utility Network project and its funding requirements within the Geospatial Inventory and Modeling Program.

A. The Utility Network project will transform the Company's current GIS platform to the Esri Utility Network Model, and establish a unified gas transmission, distribution, and stations data model in support of optimizing the core engineering and operational processes, technologies, and data. This project is an important part of the Company's GSMS and will support continuous improvement for data gathering processes governed by the Risk Management element of the GSMS. This program requires both capital and O&M funding as shown in Table 14. For the Utility Network project, the O&M projected expense is

$518,408 and the projected capital expenditure is $7,513,271 for the test year 12 months ending October 31, 2026.

Table 14: Utility Network Actual and Projected Costs

Utility Network							
	2022 Actual	2023 Actual	2024 Projected	2025 Projected	2026 Projected	Project Total	Test Year
O&M	$ -	$ 352,679	$ 722,781	$ 1,837,426	$ 196,068	$ 3,108,954	$ 518,408
Capital	$ -	$ -	$ 2,888,200	$10,970,367	$ 4,865,563	$18,724,130	$ 7,513,271

The growing business requirements for advanced analytics and business challenges presented from regulatory mandates and requirements to support a strong pipeline safety management system necessitate geospatial insight on a more granular asset level than what is currently available. Managing the distribution and transmission data in different models continues to be a challenge. The Company's current GIS platform will become unsupported as Esri's product development focus is shifting to the components that support the ArcGIS Utility Network Management extension, ArcGIS Enterprise, and ArcGIS Pro. Esri's development team has taken the existing core technology of ArcMap and the geometric network for managing gas and electric networks to the limits of its capabilities and will no longer build additional functionality. Esri utility solution partners, including several currently in use at the Company, are also moving their product lines away from the geometric network and will soon only support their solutions on the Utility Network. The project adds the following value:

(1) Mitigates risks associated with product support end of life;

(2) Enables detailed asset management and location-based analytics to bring clearer understanding around the assets that support energy delivery;

(3) Enables real-time GIS with ArcGIS Event Server (via ArcGIS Enterprise);

(4) Increases productivity through use of shortcuts, templates, and streamlined workflows within the software;

(5) Provides extensive, out-of-the-box tracing tools;

(6) Provides 3D visualization functionality;

(7) Enables users with editing tools, giving them guidance at every step of the process for developing workflows and enforcing stronger data integrity;

(8) Continues to support the concept of long transactions, enabling users to create future changes to the network model that go into effect after a certain time;

(9) Offers views of the up-to-date network in a map or schematic diagram with the ability to quickly toggle back and forth between them; and

(10) Enables archiving and historical snapshots to view the state of the gas network over time.

All these capabilities will result in greater insight and efficiency that improves the safety and delivery to customers in Michigan.

Q. Please describe Exhibit A-85 (KAP-7).

A. Exhibit A-85 (KAP-7), in accordance with Attachment 11 to the filing requirements prescribed in Case No. U-18238, provides the variances in the capital program amounts for the distribution programs that I am sponsoring compared with the Company's most recent general gas rate case, Case No. U-21490.

Q. Can you explain why columns (c), (d), (e), and (f) of Exhibit A-85 (KAP-7) do not contain any data with the exception of the EIRP?

A. The information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-21490," cannot be provided because Case No. U-21490 resulted in a settlement agreement that did not state approved capital spending amounts for the programs I am representing except for the EIRP. Thus, column (c), the "Last Approved Spending Plan" cannot be calculated for most programs. Since there is no data to display in column (c) for these programs, the information for columns (e) and (f), which seek information concerning the variances from (c), cannot be completed. As for the information for column (d), the "Actual Spending in the Test Year," cannot be completed as the test year in Case No. U-21490, which was the 12 months ending September 30, 2025, is a time period that has yet to transpire as of the filing of this case.

Q. Please summarize your direct testimony.

A. My direct testimony describes the GE&S O&M expenses and capital investments required to operate a gas distribution system that is safe and reliable. The projections included in this testimony are needed to meet customer capacity demand and regulatory requirements, modernize the system, and protect public safety. The Company's NGDP will work to enhance the Company's gas distribution system and offer additional opportunities for collaboration with municipal partners. Through the implementation of the NGDP and the execution of the projects outlined in my direct testimony above, investments that are both reasonable and necessary, the Company can provide a safe, reliable, affordable, and clean gas delivery system for its customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

JAMES P. PNACEK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is James P. Pnacek, Jr., and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Strategy Analyst.

Q. What are your responsibilities as Principal Strategy Analyst?

A. In addition to being a rate case witness, I am responsible for performance-based and Lean initiatives. I support the Company's Gas Strategy, which includes the development, recommendation, and administration of the Natural Gas Delivery Plan ("NGDP").

Q. Please describe your educational background.

A. I received a Bachelor of Science degree, with Honors, in Mechanical Engineering from Michigan State University in 1992.

Q. Please describe your business experience.

A. I joined Consumers Energy in 1992 as a Graduate Engineer in the Natural Gas Compression Department, where I was responsible for providing project management and operational support to the Company's seven compressor stations. I transferred to the St. Clair Compressor Station in 1996, where I supervised operations and maintenance employees, and had responsibility for operating and maintaining the Station. In 1998, I joined the Gas Operations Technical Support Department where I was responsible for the Gas Transmission and Storage capital budget and prioritization of the capital projects. In 2001, I joined the Gas Engineering, Regulatory, and Operating Services - Codes and Standards Group.

In this position, I was Chairman of the Gas Transmission and Storage Standards Committee, responsible for maintaining the Michigan Gas Safety Code-based standards and addressing Michigan Gas Safety Code compliance questions. In 2005, I transferred to the Electric Generation Operations Department. In this position, I was responsible for implementing and managing a Health and Safety Compliance program for Consumers Energy's electric generating plants. In 2008, I joined the Gas System and Operations Planning section of Gas Management Services and was responsible for the Gas Cost Recovery ("GCR") purchase recommendations and management of Storage Field Inventory. I assumed my current duties and responsibilities in Gas Strategy in September 2021.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have filed testimony and/or testified in GCR Reconciliation Case Nos. U-16924-R, U-17133-R, U-17334-R, U-17693-R, U-17943-R, U-20075, U-20209, U-20233, and U-20542. I have also filed testimony in Gas Rate Case No. U-21490 and End-Use Transportation proceeding in Case No. U-17900.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony provides a detailed description of the projected Operating and Maintenance ("O&M") expenses for the Company's Gas Operations Division that are necessary to allow the Company to meet public safety, compliance, and operating requirements, while delivering an excellent level of service to customers. I will explain the Company's Gas Operations Division O&M expenses for the projected test year 12 months ending October 31, 2026, to be referred to as "test year" or "2025 – 2026 Test year" in my testimony. My direct testimony is divided into two parts: (i) Gas Operations O&M expenses and (ii) Information Technology ("IT") projects.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-86 (JPP-1)	Summary of Actual & Projected O&M Expenses: Operations, Maintenance & Metering, Field Services, Other Operations;
Exhibit A-87 (JPP-2)	Summary of Actual & Projected O&M Expenses: Operations, Maintenance & Metering Programs;
Exhibit A-88 (JPP-3)	Summary of Actual & Projected O&M Expenses: Field Operations Services; and
Exhibit A-89 (JPP-4)	Summary of Actual & Projected O&M Expenses: Other Operations.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

GAS OPERATIONS O&M EXPENSES

Q. Please describe the Gas Operations Division.

A. The Gas Operations Division is committed to meeting the needs of Consumers Energy's natural gas customers through the delivery of services in a safe, reliable, cost-effective, and timely manner. The division manages the routine, ongoing customer-facing operations and maintenance of the Company's distribution and transmission systems. The O&M expenses for Gas Compression will be covered in Company witness Timothy K. Joyce's testimony. The Gas Operations Division manages the O&M programs described more fully below.

Q. What are the major O&M programs that are managed within the Gas Operations Division?

A. The four major O&M programs within the Gas Operations Division are as follows:

1. Operations, Maintenance, and Metering
2. Field Operations Services
3. Work Management and Customer Delivery
4. Operations Management

Q. Were there any changes to the major O&M programs within the Gas Operations Division for this case?

A. Yes. The Operations Performance program that was formerly part of the Gas Operations Division testimony was reorganized with a portion moving to the IT and to Lean organizations. However, a new program called Work Management and Customer Delivery was created from the remaining Operations Performance organization, and that portion of the former organization remains in my testimony.

Q. Please define and discuss the term Standard Labor Rate ("SLR") as it is used within the context of your testimony.

A. The SLR is a cost allocation mechanism used by the Company to assign a direct labor dollar value to an individual work order. A direct labor dollar value is calculated starting with the direct labor hours spent completing a work order, then multiplying those hours by the SLR. The SLR represents an average payroll cost that considers regular time payroll costs, overtime payroll costs, and paid absence payroll costs. The specific dollar value of an SLR is reviewed periodically to update the rate for any changes in regular time, overtime, and paid absence payroll costs. For forecasts developed for future years, SLRs generally reflect current payroll costs levels with an annual forward-looking adjustment of 3% per year, which is consistent with the contractual labor agreement between the Company and its operating employees' union.

Q. Please define and discuss the term Indirect Labor as it is used within the context of your testimony.

A. Indirect Labor is a cost allocation mechanism used by the Company to assign payroll costs to a work order for periods of operating employee working time not directly attributed to a specific work order. Examples of these indirect working time costs include beginning of day or end of day administrative tasks, travel time between job sites, and meetings. Indirect Labor costs are allocated to specific work orders using indirect labor loading rates. These loading rates vary across different operating employee work groups and are reviewed periodically to manage any variances between actual indirect labor costs incurred and the amounts applied to work orders.

Q. Please describe how vehicle costs are generally applied to a work order.

A. Vehicle costs are allocated to work orders using vehicle loading rates, which are applied to the Direct Labor costs of a work order. Vehicle loading rates will vary between the various operating employee work groups, and these rates are reviewed periodically to manage any variances between actual vehicle costs and the amounts applied to work orders.

Q. How has the Company projected its Gas Operations Division O&M expenses for the test year?

A. The Company has identified the O&M expenses for the test year that are necessary to meet public safety and customer service requirements. The total amount of Gas Operations O&M expenses for which I am requesting recovery during this time period is $133,635,000 as shown on Exhibit A-86 (JPP-1), line 6, column (e). These forecasts reflect the Company's expectations for work activity as measured in units and/or orders, resource requirements as measured by jobsite hours for each program, and the associated expense amount for each program.

Q. Please explain the source of the 2023 actual and derivation of the projected test year O&M expenses for the Gas Operations expenses shown on Exhibit A-86 (JPP-1).

A. The 2023 actual O&M expense amount of $111,299,000 as shown on Exhibit A-86 (JPP-1), line 6, column (b), for Gas Operations is derived from Consumers Energy's internal records. The projected test year expense levels for the Gas Operations Division programs were derived as explained below for each program. Unless otherwise noted, the program projections for the test year were calculated using a weighted average of the 2025 and 2026 forecast amounts, which reflect the Company's recent historical experience of monthly O&M expenses for individual programs.

The projected test year expense level of $133,635,000 will allow the Company to meet customer service, deliverability, and safety requirements.

Q. Please explain the merit increase and inflation calculations that have been provided in Exhibit A-87 (JPP-2), page 2; Exhibit A-88 (JPP-3), page 2; and Exhibit A-89 (JPP-4), page 2.

A. These specific pages of my exhibits present the anticipated amount of O&M expense increases that can be expected by applying either an inflation rate or a merit increase rate, or both, to historical O&M expense. Inflation was not used to determine the program funding in this case, however the following is an explanation of the exhibit.

Column (b), which is titled "Actual 12 Mos Ending Dec 31, 2023" shows the historical O&M expense. Column (c), entitled "Base O&M for Merit and Inflation 12 Mos Ending Dec 31, 2023" shows the amount of historical expense the Company believes should be used as the base for calculating merit and inflation adjustments. The Company has excluded Operating Maintenance & Construction ("OM&C") employee direct labor and indirect labor from the base for merit and inflation calculations because the future increases in those costs reflect the current working agreement the Company has with its OM&C workforce. Columns (d), (f), and (h) show the merit and inflation amounts calculated for each respective period. Increases or decreases that have been projected using other methods, such as changes in OM&C labor rates applied to work orders or other workload changes, are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i); column (j) is aligned with the Company's projected expenses for each sub-program for the test year, as shown on page 1 of my respective exhibits.

The inflation values in Exhibit A-87 (JPP-2), page 2; Exhibit A-88 (JPP-3), page 2; and Exhibit A-89 (JPP-4), page 2 were all set to 0.0% for 2024, 2025, and the test year. Therefore, column (i) represents the increase (or decrease) in O&M expenses when comparing the test year to 2023 Actuals. The projected increases from 2023 to the test year are explained for each sub-program as part of my direct testimony.

Q. Are there any Employee Incentive Compensation Program ("EICP") O&M expenses included in your exhibits?

A. No, there are not. The direct testimony and exhibits of Company witness Amy M. Conrad contain the Gas Operations Division EICP O&M expenses.

Q. Are there any Injuries and Damages expenses included in your exhibits?

A. No, there are not. The direct testimony and exhibits of Company witness Matthew J. Foster contain the Gas Operations Division Injuries and Damages expenses.

<u>Proposed Leak Detection and Repair Regulations</u>

Q. Does the Company anticipate any new regulations from the Pipeline and Hazardous Materials Safety Administration ("PHMSA") during the test year?

A. Yes. The Company anticipates that PHMSA will adopt proposed regulatory amendments that implement congressional mandates in the *Protecting the Infrastructure of Pipelines and Enhancing Safety Act of 2020* ("PIPES Act"). The objective of the PIPES Act is to reduce methane emissions from new and existing gas transmission pipelines, distribution pipelines, and underground natural gas storage facilities. PHMSA's proposed regulatory amendments are otherwise referred to as Leak Detection and Repair ("LDAR") rules.

Among the amendments for part 192 Regulated Gas Pipelines are:

- Strengthened leakage surveys, and patrolling requirements,
- Performance standards for advanced leak detection programs,
- Modified leak grading and repair criteria with mandatory repair timelines,
- Requirements for mitigation of emissions from blowdowns,
- Pressure relief device design, configuration, and maintenance requirements, and
- Clarified requirements for investigating failures.

Finally, PHMSA expanded reporting requirements for operators of all gas pipeline facilities within DOT's (Department of Transportation) authority.

More specifically, these mandated requirements will require the Company to perform the following tasks that will incur additional O&M expense:

- Increase the frequency of the periodic Leak Surveys the Company currently performs,
- Increase the frequency of Line Patrols the Company currently performs,

- Accelerate timeline for Leak Repairs,
- Perform Post Repair Inspection and any necessary remediation within the mandated period, and
- Conduct Environmental Change Surveys to investigate known leaks.

The Company expects the rule to be published by January 2025, with an anticipated effective date six months later. The Company anticipates that the LDAR rules will include a phase in period, with full compliance with these requirements expected in January 2028.

Q. Please describe the PHMSA's LDAR requirements the Company is expecting to be required to comply with during the test year.

A. PHMSA proposes to require operators to complete repairs of grade 2 leaks known to exist on or before July 2025, the Company's anticipated effective date of the rule, within one year from the date of publication of the final rule. The expected compliance date with this portion of the rule is January 2026. Also, PHMSA proposes to require a grade 3 leak known to exist on or before the effective date of the rule be repaired within three years from the date of publication of the final rule. The expected compliance date with this portion of the rule is January 2028. In addition, PHMSA proposes to require operators to complete repairs of any leak on a gas transmission line in a High Consequence Area (HCA), Class 3 or Class 4 location known to exist on or before the effective date of the rule within one year from the date of publication of the final rule. The expected compliance date with this portion of the rule is January 2026.

Q. Please describe the Company plan to comply with the leak backlog requirements of the proposed rule.

A. Based on the Company's understanding of the compliance timeline of the regulation, the Company will not request full compliance funding in this case for O&M expenses related to the LDAR rule set forth in the Notice of Proposed Rulemaking and as modified from the Gas Pipeline Advisory Committee ("GPAC") LDAR meetings. However, based on the proposed known leak elimination requirements of the rule, considering the benefits to public safety, and the Company's desire to further reduce risk, the Company will ask for funding for this portion of the LDAR requirements. The Company plans to eliminate the backlog of known leaks on the system at an accelerated rate as part of the work plan, regardless of the timing of the LDAR rule publication. The Company plans to spend $1,300,000 to address the anticipated leak backlog on the system for the test year in the Leak Survey and Repair program section of my testimony. The Company realizes the final rule has not yet been published, and substantive changes could be made to the rule resulting in meaningful changes to the costs projected in this case. Therefore, the Company is requesting the Commission approve the ability to defer any test year O&M expense that occurs as a result of the requirements of the final rule that are above the requested funding in this case. It is important to note the regulation is expected to be published at or shortly after the filing of this case, therefore the Company expects to have additional data available during the discovery phase of this case.

<u>Operations, Maintenance, and Metering</u>

Q. Please describe the O&M expenses related to the Operations, Maintenance, and Metering sub-programs shown on Exhibit A-87 (JPP-2).

A. The Operations, Maintenance, and Metering sub-programs include the operation and maintenance of the Transmission and Distribution system. Major assets in these sub-programs include mains, services, pipelines, storage fields, meters, city gates, valves, and regulators. The sub-programs also include leak survey and repair, damage repair, odor response, meter reading, meter services, right of way clearing, and staking. The Operations, Maintenance, and Metering sub-programs include several customer demand programs related to the front-line operations of the natural gas service and natural gas distribution areas of the Company. Gas Transmission employees focus on safely maintaining the Company's above and underground transmission system (pipelines, meters, regulators, city gates, and storage fields).

Gas Distribution employees primarily focus on safely maintaining the Company's underground facilities (gas mains and services), meter stands, and regulation facilities. Gas service employees focus on safely maintaining the Company's above ground facilities (such as meters and meter piping). Each sub-program is more fully described below.

<u>**Distribution Cathodic Protection**</u>

Q. Please describe the O&M expenses related to the Distribution Cathodic Protection sub-program.

A. This program is associated with regulatory-required corrosion control activities of the gas distribution system. Cathodic protection reduces the corrosion on steel main that could lead to natural gas leaks over time. The Company is projecting test year spending of $2,915,394 on Distribution Cathodic Protection.

Q. Please provide a breakdown of the work being performed in the test year for the Distribution Cathodic Protection sub-program.

A. This program includes O&M expenses for annual pipe-to-soil readings, bi-monthly rectifier and foreign bond readings, interference testing, diagnosis of sectors not meeting cathodic protection criteria, and repairs to downed sectors to meet code requirements. The Company currently has 49,447 test points read annually for pipe-to-soil readings, as well as an additional 1,483 bi-monthly reads at rectifiers and designated bond points. The annual test point reads by Headquarters for this sub-program are summarized in the following table:

Table 1

2025 Annual Reads Per Headquarters	
Work Headquarters	**Annual Read at Designated Test Points Complete 100% of These Reads Impacts Year 2026**
Adrian	429
Alma	945
Bad Axe	617
Bay City	1,996
Cadillac	94
Flint	4,910
Greenville	606
Groveland	2,715
Hastings	575
Howell	1,061
Jackson	1,686
Kalamazoo	3,375
Lansing	3,795
Livonia	6,258
Macomb	7,945
Marshall	224
Midland	1,277
Owosso	905
Royal Oak	6,957
Saginaw	3,077
Total	49,447

For the test year, the Company will have approximately 49,447 test points to read for pipe-to-soil readings. The Company's test points vary from year to year as it installs new plastic main, which changes the design of cathodic protection for that section of pipeline.

For the test year, the Company will have 1,438 bi-monthly reads at rectifiers and designated bond points. The overall number of reads has reduced as the Company installs remote monitoring units ("RMUs") that reduced the bi-monthly requirements during the months of January, May, July, September, and November.

The bi-monthly reads by Headquarters for this sub-program are summarized in the following table:

Table 2

2025 Bi-monthly Reads (Includes Rectifiers and Bond Points)							
Work Headquarters	**Jan**	**Mar**	**May**	**Jul**	**Sep**	**Nov**	**Total**
Adrian	0	13	0	0	0	0	
Alma	7	41	7	7	7	7	
Bad Axe	0	14	0	0	0	0	
Bay City	2	41	2	2	2	2	
Cadillac	0	10	0	0	0	0	
Flint	2	87	2	2	2	2	
Greenville	0	15	0	0	0	0	
Groveland	6	79	6	6	6	6	
Hastings	2	27	2	2	2	2	
Howell	1	33	1	1	1	1	
Jackson	14	64	14	14	14	14	
Kalamazoo	15	164	15	15	15	15	
Lansing	9	88	9	9	9	9	
Livonia	5	68	5	5	5	5	
Macomb	5	38	5	5	5	5	
Marshall	3	16	3	3	3	3	
Midland	0	31	0	0	0	0	
Owosso	2	29	2	2	2	2	
Royal Oak	15	89	15	15	15	15	
Saginaw	0	51	0	0	0	0	
Total	88	998	88	88	88	88	1,438

In addition to the annual reads, the O&M expenses include dollars to complete three-year atmospheric above grade inspections at 2,103 locations and 120 bridge inspections in 2026. The atmospheric above grade and bridge inspection by Headquarters for this sub-program is summarized in the following table:

Table 3

2025 – 3-Year Inspections Including Contractor Bridge Inspections			
Work Headquarters	**Atmospheric Aboveground Corrosion Inspection (every 3 years) Impacts 2026**	**3-Year Bridge Inspections Impacts 2026**	**Total**
Adrian	22	2	24
Alma	35	0	35
Bad Axe	35	0	35
Bay City	103	0	103
Cadillac	6	0	6
Flint	194	11	205
Greenville	25	2	27
Groveland	62	17	79
Hastings	30	0	30
Howell	47	9	56
Jackson	142	2	144
Kalamazoo	231	4	235
Lansing	204	9	213
Livonia	128	14	142
Macomb	263	18	281
Marshall	20	2	22
Midland	38	0	38
Owosso	61	4	65
Royal Oak	233	24	257
Saginaw	224	2	226
Total	**2,103**	**120**	**2,223**

For the test year, the Company will have approximately 31 bridge locations to complete repairs on, based upon its 2023 bridge inspection results.

The Company anticipates that approximately 2,500 sectors will not meet cathodic protection requirements within the given test year based upon historical trends.

Sectors will not meet criteria for a variety of reasons, including third-party damages to cathodic bond wires, foreign utility crossings that draw cathodic protection voltage away from steel gas mains, and anode/groundbed lifespan deterioration. This historical trend in this sub-program is summarized in the following table:

Table 4

Historical Data 2023 and 2024 Downed Sectors	
2023	**2024 YTD September**
2,217 downed sectors	1,978 downed sectors

In addition to the annual reads, inspections, and diagnostic work, the O&M expenses also include dollars to complete approximately 700 repairs in combinations of coating repair, above and below grade short removal, test wire repairs, rectifier repairs, groundbed repairs, and atmospheric corrosion repairs on service risers. These expenses are projected based on historical information and include the number of annual and bi-monthly survey reads that must be completed each year/month in compliance with regulatory standards.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 5

Distribution Cathodic Protection Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Distribution Cathodic Protection – Non-WBS	$220,837	$252,107
Cathodic Protection – Contractor; Material and Other Expenses	$505,839	$577,463
Cathodic Repairs	$198,640	$226,767
Sector Diagnosis	$254,433	$290,460
Annual Pipe to Soil Survey	$1,097,498	$1,252,899
Riser Wraps – Non-Leak Maintenance	$44,268	$50,536
Bi-Monthly Survey	$232,274	$265,163
Total Program	$2,553,789	$2,915,394

Q. What is the basis for determining the $2,915,394 of projected O&M expenses in the test year for this sub-program?

A. Projected test year spending in this sub-program is primarily driven by annual reads, inspections, repairs, reduced contractor utilization, and diagnostic work. The historical and projected activity for Company crews in this sub-program is summarized below in the following table:

Table 6

Distribution Cathodic Protection Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**Units/Orders**	**Hours**	**Program Dollars**
2016	31,705	24,616	$2,377,667
2017	40,664	19,127	$2,783,055
2018	44,794	20,222	$3,762,986
2019	52,924	15,029	$2,477,811
2020	43,146	15,720	$3,190,166
2021	52,355	13,353	$3,140,486
2022	35,514	13,451	$2,677,564
2023	40,443	11,056	$2,553,789
2024 Projected	50,325	11,303	$1,988,742
2025 Projected	49,526	9,274	$1,835,255
2025-2026 Test year	49,874	9,474	$2,915,394

The Company's projection for Distribution Cathodic Protection test year spending is based on a weighted average of the 2025 (3%) and 2026 (97%) forecast amounts, which reflects the Company's historical experience of program expense timing.

<u>Pipeline – Distribution</u>

Q. Please describe the O&M expenses related to the Operations and Maintenance Pipeline – Distribution sub-program.

A. The Operations and Maintenance Pipeline – Distribution sub-program includes multiple activities that ensure safe and reliable delivery of gas to customers' homes. For this sub-program, the Company is projecting test year spending of $11,512,760.

Q. What work is undertaken as part of the Operations and Maintenance Pipeline – Distribution sub-program?

A. This sub-program includes customer-requested work requiring alterations to existing gas mains and services, including new business branch services, meter and service relocations (where the entire service from the main to the meter is not installed or replaced) and replacing risers for installation of new meters. Where the entire service from main to meter is installed or is replaced, the costs become capital and are not included in this program. With respect to the condition of Company assets, the work activities include designated valve repairs, cross bore repairs, inside meter inspection, no-gas investigation and repair, non-leaking maintenance activities such as repairing or replacing lockwing valves to allow emergency shut-offs, replacing mushroomed plastic risers, replacing copper risers due to atmospheric corrosion, lowering main or service facilities if grade has changed, installing and pumping drips on the standard (low) pressure system thereby helping to alleviate water infiltration and freezing of service lines and meters, and property restoration costs. This sub-program also includes site checking activities to ensure customer locations are ready for work and improve efficiency and on-time delivery by avoiding unnecessary field trips by distribution crews. Site check activities additionally include confirming all jobsite requirements have been met, such as underground facility staking, sewer lead locations, final grade established, and site readiness prior to the arrival of distribution construction crews. In addition, electric usage utility costs for the gas distribution regulation facilities and the inspections at the Huron Compressor Station are both included in this sub-program. The historical year costs and projected test year costs for this program are summarized in the following table:

Table 7

Operation & Maintenance – Distribution Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Material Condition Emergent	$781,582	$1,008,223
Material Condition	$3,630,493	$4,683,256
Huron Compressor Station	$116,506	$150,290
Main & Services Alterations	$1,858,802	$2,397,813
Property Restoration	$1,036,362	$1,336,884
Site Checks	$225,909	$291,417
Pre-fabrication Costs	$738,160	$952,210
Other, including Non-WBS, Utilities	$536,961	$692,667
Total Program	$8,924,773	$11,512,760

Q. What is the basis for determining the $11,512,760 of projected O&M expenses in the test year?

A. Projected test year spending adjustments are driven by the following changes in the workplans:

- Adding the no-gas investigation and repair work,
- Increased number of non-leak maintenance (NLM) orders based on the rotation of area being surveyed and improved training to ensure all NLMs are identified,
- Alignment with customer-requested workload,

- Managing third-party contractor costs of performing this work, such as temporary traffic control and hydrovac usage.

The 2024 and 2025 projections anticipate increases to workload completion and increased labor rates for Distribution and Service employees.

Distribution and Service worker hourly standard labor rates are expected to be:

Table 8

	Distribution				**Service**			
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2023	$69.86	$37.72	$43.31	$150.90	$70.23	$105.35	$25.99	$201.56
2024	$73.41	$39.64	$33.77	$146.82	$73.80	$98.15	$22.14	$194.09
2025	$75.58	$40.81	$40.81	$157.21	$75.63	$102.86	$22.69	$201.18
2026	$78.47	$42.37	$42.37	$163.22	$78.52	$106.79	$23.56	$208.86

This historical and projected activity in this sub-program is summarized in the following table:

Table 9

Operations & Maintenance – Distribution Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**Units/Orders**	**Hours**	**Dollars**
2016	10,612	37,298	$5,787,716
2017	9,415	40,679	$6,878,971
2018	10,023	43,952	$8,241,128
2019	10,722	40,430	$7,998,681
2020	9,064	43,157	$7,850,034
2021	13,755	59,207	$11,721,014
2022	9,983	47,774	$10,531,290
2023	9,370	40,741	$8,924,773
2024 Projected	17,132	45,017	$10,814,580
2025 Projected	14,708	41,450	$9,066,529
2025-2026 Test year	16,703	53,172	$11,512,760

The Company's projection for the Operations and Maintenance Pipeline – Distribution sub-program test year spending is a weighted average of the 2025 (7%) and

2026 (93%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>**Pipeline – Transmission**</u>

Q. Please describe the O&M expenses related to the Operations and Maintenance Pipeline - Transmission sub-program.

A. The Operations and Maintenance Pipeline - Transmission sub-program includes expenses related to performing:

(a) Code Inspections,

(b) Third-party oversight and staking per MISS DIG 811 Underground Facility Damage Prevention and Safety Public Act 174 ("Act 174") of 2013, ("MISS DIG 811"),

(c) Demand Maintenance,

(d) Preventive Maintenance & Operations,

(e) Restoration/Right-of-Way ("ROW"), and

(f) Miscellaneous Expenses.

This sub-program ensures public safety by maintaining the integrity of the Company's gas transmission pipeline system through inspection and repair of all critical assets to sustain proper operating conditions. Sub-program funding also includes necessary maintenance of valves sites, buildings, fencing, and security systems and structures. For this sub-program, the Company is projecting test year spending of $3,741,356.

Q. Please provide a description of the work activities in the Operations and Maintenance Pipeline - Transmission sub-program.

A. This sub-program includes the following work activity categories.

- Code Inspections include completing Michigan Gas Safety Standards ("MGSS") and Michigan Department of Environment, Great Lakes, and Energy ("EGLE") code inspections associated with pipeline valves, pipe, and associated assets. This work is generally completed by Company employees and code inspection orders typically include labor and ancillary material costs. Examples of these inspections include vehicle and foot patrol of pipelines, leak survey, valve inspections, Pressure Limiting Device inspections, Remote Control Valve inspection, corrosion inspections, maintenance pigging, and inspection of gas quality equipment, including drip logs and separators that protect pressure regulation and customer metering equipment. One key example is line patrols where, based on class location, the Company patrols the system from one to four times per year to investigate for new dwellings, leaks, and third-party activity. As part of these line patrols, the Company takes appropriate actions to repair equipment and/or remediate in compliance with the MGSS. (MGSS code/standard/section 192.705, 192.706, 192.613, 192.935). This sub-program also includes MGSS required pipeline maintenance cleaning pig runs on five transmission lines that need to be completed annually. These pig runs are coordinated with the Company's Pipeline Integrity Program to avoid duplicate pig runs in the same calendar year. This work is included as part of the Company's Transmission Integrity Management Program.

- The Pipeline Preventative Maintenance and Operations portion of the sub-program involves proactive and necessary inspections that do not fall under code requirements but are necessary for maintaining safe, reliable, and predictable system operations for customers. Such inspections include: (a) instrument calibration; (b) launcher and receiver inspections; (c) vehicle safety inspections; (d) general safety inspections; (e) liquid drip collection; (f) housekeeping; and (g) site maintenance and other general functions.

- The Demand Maintenance portion of the sub-program accounts for labor and materials, to address pipeline assets that require repair due to performance during annual inspections, outages, or other activities. These activities typically include: (a) maintenance of valves, cathodic protection test stations, rectifiers, liquid collection equipment, pipeline markers, metering equipment, communication equipment, calibration equipment, pipe coating, sites, and facilities; (b) leak repairs; (c) ROW access maintenance; (d) third-party damage repairs; and (e) snow plowing.

- The Facilities Locating for Third Parties (MISS DIG 811) portion of the sub-program is primarily comprised of labor hours required to evaluate, locate, stake, and oversee third-party activities near transmission pipelines.

- Non-Work Breakdown Structure ("Non-WBS") portion of the sub-program includes labor, internal departmental chargebacks, contractors, and materials not directly associated with a specific work order. These costs include OM&C travel and meal charges, Company Laboratory labor for equipment calibration, storeroom stock and non-stock material issues, equipment rental charges, storage space rental, electric bills for rectifiers, and other site equipment.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes Contractor labor, credits, and materials for Code Inspection, Preventive Maintenance & Operations, Demand Maintenance, and Facilities Locating for Third Parties (MISS DIG 811) that are directly associated with a specific work order.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 10

Operation & Maintenance – Pipeline- Transmission Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Non-WBS	$710,866	$754,752
Contractor; Materials, Credits and Other Expenses	$392,062	$377,963
Code Inspections	$871,321	$782,592
Preventive Maintenance & Operations	$385,434	$365,210
Demand Maintenance	$380,031	$417,383
Facilities Locating for Third Parties (PA 174)	$1,090,828	$1,043,456
Total Program	$3,830,542	$3,741,356

Q. What is the basis for determining the $3,741,356 of projected O&M expenses in the test year for this sub-program?

A. The Company's projection for the Operations and Maintenance Pipeline – Transmission sub-program test year spending is a weighted average of the 2025 (10%) and 2026 (90%) forecast amounts, which reflect the Company's historical experience of program expense timing. As shown in the table above, projected spending in this sub-program is primarily driven by known hours for regulatory driven code inspections, preventative maintenance, and maintenance pigging activities. Demand maintenance (conditions requiring short-term response), and facility locating for third parties (MISS DIG 811), are projected based on historical trends and anticipated needs. The projected labor hour allocations for Code

Inspections are based on historical time to perform required inspections and maintenance to the assets on the transmission pipeline system.

The projected expenses associated with Facilities Locating for Third Parties (MISS DIG 811) activities are comprised of historical data and projected trends. Historically, ticket volumes have trended down due to a greater volume of tickets being processed in the office, and only actionable tickets being sent to the operational groups.

Based on the trend experienced in 2023 and the current economic growth, ticket volumes and hours are expected to be flat through 2026 (see below table).

Table 11

Miss Digs 811 Tickets and Associated Hours		
Year	**Orders**	**Hours**
2016	12,538	6,119
2017	14,440	7,000
2018	18,412	8,327
2019	20,531	10,181
2020	20,150	10,274
2021	15,931	8,633
2022	9,562	7,801
2023	9,337	8,115
Trend 2024	9,000	8,000
Trend 2025	9,000	8,000
Trend 2026	9,000	8,000

Gas Transmission worker hourly standard labor rates are expected to be:

Table 12

Transmission				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2023	$69.18	$24.90	$36.67	$130.75
2024	$72.53	$23.93	$34.81	$131.28
2025	$76.37	$26.73	$32.08	$135.17
2026	$79.28	$27.75	$33.30	$140.33

The historical and projected activity in this sub-program is summarized in the following table:

Table 13

Operations–& Maintenance - Pipeline Hours & Dollars		
Year (Jan-Dec)	**Hours**	**Dollars**
2016	24,033	$2,675,390
2017	21,865	$2,131,709
2018	23,556	$2,670,236
2019	26,639	$3,121,709
2020	23,634	$3,012,604
2021	20,676	$3,198,861
2022	21,783	$4,221,974
2023	17,879	$3,830,542
2024 Projected	14,253	$3,456,218
2025 Projected	14,212	$3,017,218
2025-2026 Test year	18,631	$3,741,355

<u>**Regulation Distribution**</u>

Q. Please describe the O&M expenses related to the Operations and Maintenance - Regulation Distribution sub-program.

A. The Operations and Maintenance - Regulation Distribution sub-program is responsible for delivering safe and reliable gas service pressure to customers. For the test year, the Company is projecting spending $8,496,643 for this sub-program. This program consists of all code compliance requirements for regulation stations and odorant facilities statewide. This includes all required annual inspections, and maintenance and repairs of these facilities. The sub-program ensures gas delivery to customers with a detectible odor required for public safety. Inspection of critical designated valves that isolate sections of the distribution pipeline system during planned outages or emergencies is also included in this sub-program. This is critical for system operations and public safety. The Regulation

Distribution sub-program is responsible for the statewide inspection, maintenance, and repair of:

- 662 Distribution Regulation Stations,
- 1,660 1-inch and larger high-pressure regulation stands,
- 100 Odorant Injection Facilities, and
- 7,270 Designated Pipeline Valves.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 14

Operation & Maintenance – Regulation Distribution Projection Breakdown by Activity Type		
	2023 Actual	**2025-2026 Test year**
Designated Valves	$1,409,923	$1,420,059
Regulation Inspection	$3,924,357	$3,952,570
Regulation Repairs	$2,425,685	$2,443,123
Vegetation Management	$676,030	$680,891
Total Program	**$8,435,995**	**$8,496,643**

Q. What is the basis for determining the $8,496,643 projected O&M expenses in the test year for this sub-program?

A. To efficiently and safely operate the distribution pipeline system, the Company continues to invest in new regulation facilities (city gates and distribution regulator stations). These investments are sponsored by Company witness Michael P. Griffin. These new or upgraded facilities have additional equipment and technology installed that requires annual inspection and maintenance. Examples include Supervisory Control and Data Acquisition ("SCADA") communication components, transducers, catalytic heaters, gas pipeline filter separators, odorant pump injection systems, additional designated blow-down valves on

Transmission Operated as Distribution pipe ("TOD"), and poly valves as required on all new gas main installed.

The historical and projected activity in this sub-program is summarized in the following table:

Table 15

Operations & Maintenance – Regulation Distribution Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**Units/Orders**	**Hours**	**Dollars**
2016	5,129	41,366	$4,609,086
2017	5,009	38,058	$4,330,964
2018	6,240	40,943	$6,169,182
2019	7,672	40,350	$5,909,548
2020	8,246	42,432	$6,363,894
2021	13,651	43,728	$7,662,838
2022	10,701	52,315	$9,126,940
2023	10,641	47,443	$8,435,995
2024 Projected	12,118	45,774	$8,078,355
2025 Projected	12,785	44,291	$8,048,289
2025-2026 Test year	13,435	45,433	$8,496,643

The projection for the test year is a weighted average of the forecasts for 2025 (9%) and 2026 (91%), which reflects the Company's recent historical experience with the timing of program expenses.

<u>Measurement and Regulation Transmission</u>

Q. Please describe the O&M expenses related to the Operations and Maintenance - Measurement and Regulation Transmission sub-program.

A. The Operations and Maintenance - Measurement and Regulation Transmission sub-program is primarily responsible for gas measurement, pressure control, and gas quality for the Company's transmission system, which feeds the distribution system as well. This work is driven by MGSS, EGLE, Department of Transportation, Federal Energy

Regulatory Commission ("FERC"), PHMSA, Occupational Safety and Health Administration, and Sarbanes Oxley ("SOX") controls. This includes third-party supplies and metering to meet SOX requirements as well as lost and unaccounted fuel custody requirements. This sub-program also includes expenses relating to the inspection and repair of data acquisition systems, metering, pressure control valves and regulators, overpressure protection, odorization, gas quality analyzers, and gas conditioners. These inspections can include piping, regulators, transducers, SCADA, valves, operators, emergency shut down devices, separators, heaters, meters, relief valves, and odorizers. Also included are monitoring and operating gas quality and analysis equipment such as chromatographs, which measure for water (H_20), hydrogen sulfide (H_2S), carbon dioxide (CO_2), oxygen (O_2), and testing for Polychlorinated Biphenyls (PCB). Other expenses include vehicles, maintenance equipment, utility bills, regulatory permits, and general cost to maintain city gate sites, buildings, fencing, and security. This sub-program ensures the safety and compliance of Company gas transmission and distribution pipeline systems through inspection and repair of all critical assets to meet federal, state, and local agencies' regulatory requirements.

Q. Please provide a description of the work activities in the Operations and Maintenance - Measurement and Regulation Transmission sub-program.

A. This sub-program includes the following work activity categories.

- The Demand Maintenance projected expense accounts for labor, material, and contractor supported activities to perform repairs on measurement and regulation assets. These repairs can arise from code inspections or failed equipment that requires immediate or scheduled actions. This activity covers all required emergent work relating to safety or system improvements to ensure the flow of gas and material readiness. Examples include driveway stone and repairs, filters for separators and liquid extraction, building repairs and permitting, painting, brush and tree removal, landscaping, fencing, lighting, RTU repairs, transducer and ultrasonic instrumentation, and required investigations to respond to gas control alarms, including RTU device communication failures. The additional equipment added to the system results in the increased units.

- The Preventative Maintenance projected expense supports performing proactive and necessary inspections that do not fall under the code requirements but are necessary for maintaining safe, reliable, and predictable system operations. Such inspections include Remote Terminal Unit ("RTU") inspections, instrument calibration, liquid drip collections, pilot filter replacements, winter system operational checks, non-code valve inspections, general site inspections, pressure changes, heater maintenance, orifice plate inspections, painting, and grade work. Additionally, preventative maintenance includes labor hours and material costs to maintain site access and conditions including access drive and site stone, grass and weed spraying and mowing, and fence condition. These costs are forecasted based on the number of facility locations that require regular maintenance as well as condition-based needs.

- The Inspections projected expense primarily consists of Company employee labor hours, services, and necessary material costs. Labor hour projections are based on historical time to perform inspections, required maintenance, and standard work initiatives to meet code, manufacturer recommendations, deliverability, and reliability of gas systems. Inspection units increase as new equipment (gas filtration, liquid separation, gas analyzers, chromatographs, and regulation) is being added to the system. Also, regulation and other ancillary equipment has been added, such as filter-separators and multiple station outputs to meet customer demands. The Inspection activity levels satisfy safety and compliance regulatory requirements of our gas transmission and distribution pipeline systems through inspection and repair of all critical assets to meet regulatory requirements.

- The Non-WBS portion of the sub-program is comprised of labor, materials, and services not associated with a work order. These costs include (a) travel and meal charges, (b) Company laboratory labor for equipment calibration, (c) stock and non-stock material, (d) heater glycols, (e) valve grease, (f) equipment rental charges, (g) storage space rental, (h) purchase power, (i) SCADA cellular bills, (j) repair parts, (k) outside services, (l) contractors, (m) buildings, (n) testing in laboratory services, and (o) parts and materials to support system operations and code work. This portion of the sub-program also includes actions needed to comply with governmental agencies and local ordinances. Costs here are projected based on historical spend.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes contractor labor, credits, and materials for inspections, preventive maintenance and operations, demand maintenance, and third-party contracts which are directly associated with a specific work order.

The historical year costs and projected test year costs for this program are summarized in the following table:

Table 16

Operation & Maintenance – Transmission Measurement & Regulation Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Non-WBS	$27,634	$206,363
Contractor; Materials, Credits and Other Expenses	$632,804	$655,373
Demand Maintenance	$597,885	$529,575
Preventative Maintenance	$1,352,067	$1,210,456
Inspections	$649,098	$580,010
Third Party Contracts	$237,088	$201,743
Total Program	$3,496,577	$3,383,519

Q. What is the basis for determining the $3,383,519 of projected O&M expenses in the test year for this program?

A. The test year amount of $3,383,519 is a weighted average of the 2025 (15%) and 2026 (85%) forecast amounts shown above. This reflects the Company's historical experience of program expense timing. Much of the projected expense in this sub-program is derived from the Company's estimated gas transmission field worker jobsite hours.

Each activity includes a forecasted number of units and associated expected average amount of time to complete each unit. The units multiplied by the time to complete, along with anticipated labor rates, account for much of the cost projection. In total, the Company projects jobsite labor hours to be 17,737 hours during the test year in this proceeding.

Gas Transmission worker hourly standard labor rates are expected to be:

Table 17

Transmission				
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2023	$69.18	$24.90	$36.67	$130.75
2024	$72.53	$23.93	$34.81	$131.28
2025	$76.37	$26.73	$32.08	$135.17
2026	$79.28	$27.75	$33.30	$140.33

The historical and projected activity in this program is summarized in the following table:

Table 18

Operations & Maintenance – Measurement & Regulation Transmission Hours & Dollars		
Year (Jan-Dec)	Hours	Dollars
2016	18,233	$4,609,086
2017	20,497	$3,461,000
2018	20,497	$3,074,000
2019	20,722	$3,005,000
2020	18,540	$2,897,776
2021	17,795	$3,188,919
2022	17,197	$4,339,305
2023	20,394	$3,496,577
2024 Projected	17,936	$3,433,865
2025 Projected	17,737	$3,258,089
2025-2026 Test year	17,737	$3,383,519

<u>**Odor Response**</u>

Q. Please describe the O&M expenses related to the Odor Response sub-program.

A. This sub-program provides for around-the-clock response to odor calls and other emergencies, including initial response to third-party damages. The Company has been achieving an average annual response time of 30 minutes or less, to ensure the safety of customers and the public.

The Commission monitors the Company performance on response times to ensure the safety of customers and the public. The program consists of Company employee labor costs inclusive of material and fleet costs.

This sub-program deals with initial response to odor calls from customers and the general public. Final resolution of the odor calls, if determined to be caused by leaking gas from Company facilities, may be an O&M repair or a capital asset replacement. The costs of this sub-program cover the O&M portion of the final resolutions. The O&M portion is based on a historical two-year analysis, which is reviewed every year (using a rolling two-year average). This portion/average will fluctuate based on whether the leaks found on gas services and mains are repaired or replaced.

The Odor Response sub-program consists of labor costs that are based on the Reasonable Expectancy to complete each work activity along with known labor rates for the personnel completing the activity. Activities such as the leak investigation standard (six-house check) implemented by the Company in 2018, provides for a more thorough leak investigation. The standard requires Company employees to check the house for which the leak was called in as well as a six-house check, including the buildings next to the reported address and the three buildings on the other side of the main (which are often across the street). They check for leak sources at the service riser/entrance of these buildings.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 19

Odor Response Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Odor Response	$6,308,854	$6,440,887
Total Program	**$6,308,854**	**$6,440,887**

Q. What is the basis for determining the $6,440,887 of projected O&M expenses in the test year for this sub-program?

A. The Company has projected the costs of the Odor Response sub-program based on expected workload associated with 42,222 O&M odor response orders.

Each odor response call is expected to require gas service worker jobsite time of 0.75 hours, or about 45 minutes. This expected time requirement is based on reviews during 2023 and 2024 of jobsite time per order completed.

The test year also reflects projected gas service worker hourly standard labor rates, indirect labor rates, and vehicle rates.

Gas Service worker hourly standard labor rates are expected to be:

Table 20

Service				
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2023	$70.23	$105.35	$25.99	$201.56
2024	$73.80	$98.15	$22.14	$194.09
2025	$75.63	$102.86	$22.69	$201.18
2026	$78.52	$106.79	$23.56	$208.86

The historical and projected activity in this sub-program is summarized in the following table:

Table 21

Odor Response Program O&M Units/Orders, Hours & Dollars			
Year (Jan-Dec)	O&M Units/Orders	Jobsite Hours	Dollars
2016	78,719	51,429	$6,339,803
2017	58,892	34,012	$4,521,650
2018	54,743	35,587	$5,265,338
2019	56,755	40,061	$6,146,752
2020	51,500	36,442	$5,506,217
2021	48,248	36,057	$6,159,004
2022	44,729	34,770	$6,445,000
2023	42,023	32,402	$6,308,854
2024 Projected	43,444	32,619	$6,259,031
2025 Projected	37,359	28,020	$5,640,958
2025-2026 Test year	42,000	31,020	$6,440,887

The projection for the test year, is a weighted average of the 2025 (10%) and 2026 (90%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Leak Repair and Survey

Q. Please describe the O&M expenses related to the Leak Repair and Survey sub-program.

A. The Leak Repair and Survey sub-program includes Company labor and contractor services for annual mobile and walking leak surveys, and classification of leaks on mains, services, and meter stands called in by customers or found during leak survey activity.

The sub-program also includes leak repairs to mains, services, and meter stands, including installation of leak repair fittings and clamps, tightening of fittings and clamps, partial service replacement, and rebuilds of meter installations. This work is on the Company's distribution system and helps to ensure public safety. This program includes the costs associated with contracts for maintenance of customer-owned fuel lines and will continue to include those costs as well, in compliance with regulations for master meters operators. In accordance with Mich Admin R 460.20335, the costs associated with central meters, otherwise referred to as master meter systems, run through this Leak Repair and Survey sub-program. These costs are offset by the owner of the master meter system as specified under Mich Admin R 460.20335(d)(4).

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 22

Leak Repair and Survey Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Leak Survey	$5,339,146	$5,000,000
Leak Classification	$1,573,968	$1,884,986
Leak Assessments	$517,381	$619,616
Leak Repairs – Meter Stands and Regs	$3,286,805	$4,510,960
Leak Repairs – Services	$1,553,816	$2,132,528
Leak Repair – Mains	$2,594,560	$3,531,910
Total Program	**$14,865,676**	**$17,680,000**

Q. What is the basis for determining the $17,680,000 of projected O&M expenses in the test year for this sub-program?

A. The projected expense in this sub-program is primarily driven by:

- Leak survey requirements,
- Leaks found during leak survey,
- Current actionable leaks,
- Leaks requiring repair, and
- Reducing the known leak back log.

Leak surveys are compliance driven per MGSS 192.481, 192.557, 192.613, 192.705, 192.706, 192.721, 192.723, and 192.935, which require line patrol and leak survey frequency for mains, services, and customer-owned gas systems. The frequency of leak surveys is determined by the survey type:

- Scheduled leak surveys - Required on a quarterly, semiannual, annual, three-year, or five-year basis,
- Non-scheduled leak surveys - Required on an as-needed basis,
- Contracted Customer-Owned Gas System Leak Surveys - Varies per contract,

- Discretionary leak surveys - Performed on an as-needed basis.

The Leak Surveys expense for the test year is forecasted to be higher than the previous two years with approximately 400,000 units and 10,000 miles of main. This is based on the code-required schedule and frequency of the gas facilities to be surveyed. The historical and projected **Number of Leaks found during Leak Survey** in this sub-program is summarized in Table 23. The 2024 Projected leaks in the table are based on actuals and a forecasted data.

Table 23

Leaks Found During Survey			
Year (Jan-Dec)	**Above Grade**	**Below Grade**	**Total**
2017	5,220	1,555	6,775
2018	7,931	1,715	9,646
2019	18,393	2,697	21,090
2020	9,842	1,589	11,431
2021	12,009	1,577	13,586
2022	9,714	1,516	11,230
2023	9,151	343	9,494
2024 Projected	19,478	850	20,328

The increase in leaks found, per Table 23, drives the increased required leak repairs. The historical and projected Leak Survey Units, which represents the number of services, in this sub-program is summarized in Table 25. As shown in Table 25, the 2024 projected survey units are 166,433 units higher than 2023 due to the five-year survey schedule. This increased number of surveys is the main contributor to the increase in the number of leaks found for 2024.

Leak Repair Scheduling is required per code by MGSS 192.703, 192.709, 192.711, and Michigan Admin Code R. 460.20318 - 460.20318 - Gas leak investigation;

establishment of service; Michigan Admin Code R. 460.20327 - Section R. 460.20327 - Distribution system; leakage surveys and procedures. Each leak must have a complete leak analysis completed to determine the appropriate leak classification for repair scheduling. As a result of the new leak-found trend, and an initiative to reduce the overall leak backlog, leak repair units are forecasted to be higher than average. Forecasts are based on:

(1) Code requirements regarding leak classifications and repairs on active leaks,

(2) Code requirements on leak survey frequency,

(3) Resource availability, and

(4) Historical averages.

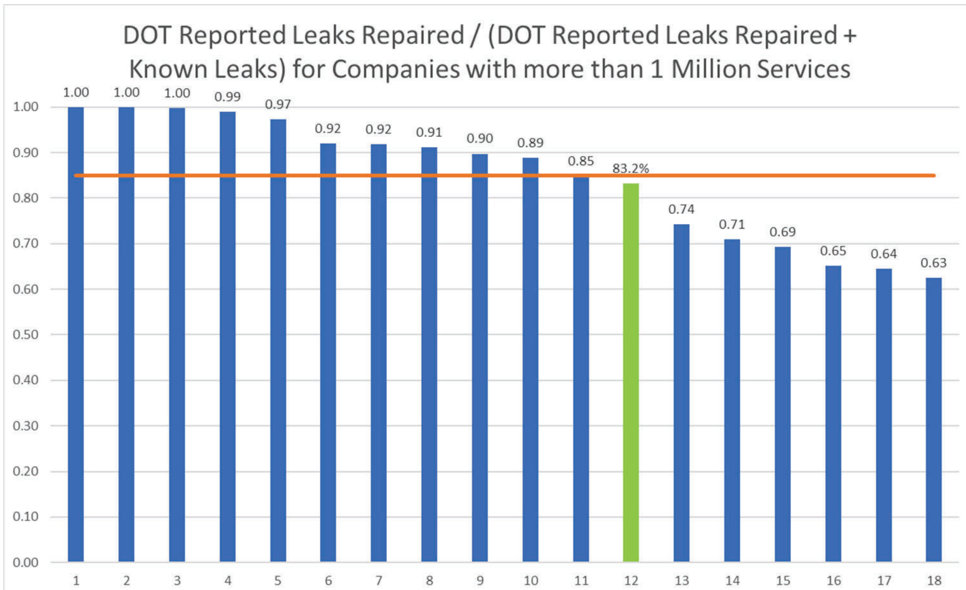
The historical and projected **Leak Repair Units** in this sub-program are summarized in Table 25. The historical and forecasted **Leak Classification** units are shown in Table 25.

The graph below depicts a comparison of natural gas utilities with more than one million customers with vintage main and is based on leaks repaired per leaks repaired and actionable leaks at year end (see the below formula).

$$\% = \frac{Leaks\ repaired}{Leaks\ repaired + Actionable\ Leaks}$$

Consumers Energy is depicted in green, and was at 83% as of year-end 2023, which is just below industry average of 85%. Based on benchmarked data, shown in Figure 1 below, the Company is seeking to position itself in the top of the first quartile, which drives improved system integrity and public safety.

Figure 1



The **leak repairs planned** for 2025 and 2026 will ensure the Company maintains a safe and reliable natural gas system by permanently repairing leaks. and working to eliminate our current leak backlog. Doing so, the Company can enhance public safety, increase the integrity of the natural gas system, reduce methane emissions, and lower long-term costs. With this plan, the Company will eliminate Grade 2 leaks by January 2026 and continue to reduce Grade 3 leaks through the test year. The NGDP will address long-term system integrity.

The projection for Company labor and vehicle costs are primarily based on the projected hours for each year. Increases in labor and vehicle costs from 2023 to the test year also reflect projected gas distribution worker hourly standard labor rates, indirect labor rates, and vehicle rates.

Gas Distribution worker hourly standard labor rates are expected to be:

Table 24

Distribution ($/hr)				
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2023	$69.86	$37.72	$43.31	$150.90
2024	$73.41	$39.64	$33.77	$146.82
2025	$75.58	$40.81	$40.81	$157.21
2026	$78.47	$42.37	$42.37	$163.22

The historical and projected activity in this program is summarized in the following table:

Table 25

Leak Repair and Survey Units/Orders, Hours & Dollars					
Year (Jan-Dec)	Survey Units	Classification Units	Repair Units	Jobsite Hours	Dollars
2016	462,334	18,734	15,814	96,196	$13,510,903
2017	556,249	13,079	13,815	67,091	$10,908,621
2018	457,641	12,650	18,556	83,858	$16,087,691
2019	480,394	13,374	21,970	98,567	$20,232,711
2020	415,305	12,923	23,649	110,011	$19,802,868
2021	491,858	7,438	18,612	97,692	$21,786,507
2022	352,437	4,695	16,537	83,987	$18,941,796
2023	368,287	3,981	14,132	60,650	$14,865,676
2024 Projected	534,720	5,566	21,402	64,244	$16,714,729
2025 Projected	350,968	5,095	21,331	64,061	$16,760,000
2025-2026 Test year	400,000	5,095	21,594	66,719	$17,680,000

The projection for the test year is a weighted average of the 2025 (5%) and 2026 (95%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Q. Please describe the LDAR Rule impacts to this program.

A. As talked about previously in my testimony, the Company plans to reduce the known leaks on the system, at an accelerated rate, as part of planned work, regardless of the timing of the rule. The Company has included $1,300,000 is this program, which was allocated among the three Leak Repair work types in Table 21.

Q. Please describe Advanced Methane Detection.

A. In 2024, the Company conducted leak surveys with handheld instrumentation through foot patrol of gas service lines and infrastructure. Advanced Methane Detection uses higher sensitivity instrumentation to detect smaller amounts of gas release than traditional tools. During the test year, the Company plans to use a Grid based approach combined with Advanced Methane Detection to perform leak survey on a portion the Company's natural gas system. Advanced Methane Detection is further explained in Company witness Kristine A. Pascarello's testimony.

Damage Repair

Q. Please describe the O&M expenses related to the Operations & Maintenance - Damage Repair sub-program.

A. The Operations & Maintenance - Damage Repair sub-program involves repairing natural gas mains, services, and meter installations from third-party damages (such as excavators, other utilities, municipalities, and homeowners). These expenses are necessary to ensure public safety, and to bring the system back into service in a timely manner. Consumers Energy's operating employees assess the site, mitigate the gas leak caused by the damage, and make necessary repairs to the system. In addition, the program is the recipient of credits from billing (less write-offs) from these third parties. These credits have shown variability year over year for several reasons, such as volume of damages, third-party response (willingness or ability to pay), and market and economic conditions.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 26

Operation & Maintenance – Damage Repair Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Service/Meter Stand Repair	$2,265,200	$2,161,752
Main Repair	$512,158	$488,768
Damage Assessment	$199,067	$189,976
Credits	($1,561,893)	($1,459,000)
Total Program	**$1,414,532**	$1,381,496

Q. What is the basis for determining the $1,381,496 of projected test year O&M expenses for this sub-program?

A. Spending in this sub-program is primarily driven by the number of damages recorded on the system. Projected costs consider historical volume and Company efforts to reduce damages to the gas system. The Company maintains a Public Safety Outreach ("PSO") function, using damage prevention liaisons, that seek to work with third parties through various channels to provide awareness of the gas system, and to prevent damages. Through PSO efforts, damage repairs are projected to be lower in 2025 and 2026. These efforts are meant to reduce costs for the damage repair portion of this program. Offsetting these cost reductions is a reduced level of damage credits being collected from or paid by third parties. A common reason for not billing a third party for damage is that the damaging party is unknown, such as when gas damage occurs, and the party leaves the scene prior to the Company arriving.

Gas distribution worker hourly standard labor rates are expected to be:

Table 27

Distribution ($/hr)				
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2023	$69.86	$37.72	$43.31	$150.90
2024	$73.41	$39.64	$33.77	$146.82
2025	$75.58	$40.81	$40.81	$157.21
2026	$78.47	$42.37	$42.37	$163.22

This historical and projected activity in this sub-program is summarized in the following table:

Table 28

Operations & Maintenance – Damage Repair		
Hours & Dollars		
Year (Jan-Dec)	Hours	Dollars
2016	17,486	$1,209,306
2017	17,497	$624,348
2018	18,685	$683,225
2019	18,471	$1,102,498
2020	23,753	$2,550,320
2021	19,644	$1,379,759
2022	23,854	$1,574,894
2023	18,402	$1,414,532
2024 Projected	17,615	$1,448,021
2025 Projected	15,898	$1,255,351
2025-2026 Test year	16,298	$1,381,496

The test year projection is a weighted average of the 2025 (18%) and 2026 (82%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Staking & Locating

Q. Please describe the O&M expenses related to the Staking & Locating sub-program.

A. The Staking & Locating sub-program involves Company labor and contractor services for the staking and locating of the Company's gas distribution pipeline facilities in accordance with Act 174 of 2013, MISS DIG 811 Underground Facility Damage Prevention and Safety Act, a key component of securing public and employee safety. Work is typically performed by a contracted outside service vendor on a multi-year contract with the Company.

Q. Please discuss the work activities in the Staking and Locating Sub-Program.

A. The Staking and Locating sub-program includes the following work activity categories:

- Outside Services – Staking and Locating: contractor costs are included for staking and locating activities that are performed under the shared resource model and advanced locating for abnormal operating conditions.
- Outside Services - Dedicated Contractor: contractor costs are included in the test year projection for staking and locating activities that will be performed under the Dedicated Contractor staking program.
- Company Labor: volumes and hours are included in the test year projection for Company labor to support standby inspections, and abnormal operating condition efforts. Included are the projected increases in labor and vehicle costs from 2023 to the test year for gas distribution worker hourly standard labor rates, indirect labor rates, and vehicle rates. The projection for Company labor and vehicle costs are primarily based on the projected hours for each year.
- Licenses, Permits & Fees: This includes the fees that Consumers Energy pays to the state MISS DIG 811 system as part of Act 174.

Q. Please provide a breakdown of the Staking and Locating sub-program expense.

A. The Staking & Locating sub-program expenses for 2023 and the test year expenses are identified in the table below:

Table 29

Staking and Locating Sub-program Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Outside Services - Staking and Locating (Shared)	$7,865,196	$0
Outside Services - Staking and Locating (Dedicated Oakland and Kent)	$2,766,691	$6,703,509
Outside Services - Staking and Locating (Dedicated remainder of service territory)	$0	$15,112,608
Company Labor	$1,401,778	$1,802,959
Licenses, Permits & Fees	$373,380	$838,409
Total Program	**$12,407,045**	**$24,457,485**

Q. What is the basis for determining the $24,457,485 of projected O&M expenses for this sub-program?

A. Spending in this sub-program is primarily driven by staking request volume (units) and the cost of staking contractors. Table 32 shows the change in staking volumes realized year over year. The primary drivers for this increase include:

(a) Increase of $1,712,991 based on anticipated contractor volume increases of 66,379,

(b) Increase of $401,181 based on Company labor standard labor rate change and increased hours,

(c) Increase in MISS DIG 811 membership fees of $465,029, and

(d) Increase of $9,470,757 based on dedicated model expansion and contractor rate increases.

- The 2024 expansion of Oakland County from 67% to 100% of the dedicated staking ticket volumes, and the 2024 addition of Kent County under the dedicate model accounts for $2,179,247 of the increase.

- The 2025 expansion of the dedicated model to the remainder of the Company's Gas Service Territory, based on performance and the staking Request for Proposal (RFP) results, accounts for $7,291,510 of the increase. The Company is mitigating a higher increase by expanding its Dedicated Contractor approach, which is available at a lower unit cost than continued use of the Shared Contractor approach and also provides numerous other benefits to customers described in more detail below.

Historical and forecasted expenses for the Staking sub-program are provided in the table below.

Table 30

O & M – Staking & Locating Total Program	
Year (Jan-Dec)	**Dollars**
2016	$5,145,070
2017	$5,828,563
2018	$6,754,042
2019	$8,200,186
2020	$7,306,455
2021	$10,982,945
2022	$10,309,238
2023	$12,407,527
2024 Projected	$15,213,591
2025 Projected	$22,653,823
2025-2026 Test year	$24,457,485

The test year expense projection is based on a weighted average of the 2025 (12%) and 2026 (88%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Q. Please describe the test year cost forecast for volume and unit cost.

A. An anticipated unit cost increase is included in the test year projection for contractor services and with the requirement for enhanced capability to manage increased demand in performance and increasing labor costs.

The staking completed by an outside contracted vendor is billed based on contractual unit costs. An anticipated volume increase of 7.0% is included in the test year projection relative to 2024 contractor services. This is in alignment with the trend of the historical data and staking forecasts for the state of Michigan. The anticipated contractor unit cost and staking volume increases is shown in the following table.

Table 31

Contractor Stake & Locate Services		
	Base Unit cost ($/unit)	**Base Unit Forecast (units)**
2022	$21.83	407,551
2023	$26.71	412,008
2024 Projected	$30.49	437,004
2025 Projected	$44.66	450,823
2026 Projected	$45.67	482,380

The Statewide MISS DIG 811 Annual Ticket Requests table below shows the change in staking volumes realized year over year.

MISS DIG 811 data (www.missdig811.org/about/who-we-are/about-miss-dig.html) shows a continuous growth in staking and locating ticket requests for the entire State of Michigan, except for a small decline in 2020, which appears to be a temporary result of COVID-19 pandemic business impacts.

The following is the historic and projected Statewide MISS DIG 811 annual ticket requests:

Table 32

Statewide MISS DIG 811 Annual Ticket Requests		
Year	**Annual Ticket Requests**	**% Change From Prior Year**
2016	814,303	
2017	872,896	7.2%
2018	923,993	5.8%
2019	1,015,753	9.9%
2020	994,573	-2.1%
2021	1,088,030	9.4%

2022	1,093,021	1.0%
2023	1,202,992	10.1%
2024 Forecast	1,323,291	10.0%
2025 Forecast	1,415,921	7% Assumed

Q. Please describes the Company's concerns with the increase in staking ticket volumes and proposed recommendation.

A. The Company has estimated staking tickets for the test year based on the best information available at this time. With staking requests increasing due to fiber optic and other infrastructure work, the actual staking demand the Company experiences in 2026 could be above the company's staking volume forecast. While the Company attempts to forecast staking volumes with a high degree of accuracy, the largest factors influencing expenditures in these programs are externally driven. As a result, the Company requests it be allowed to defer for refund or recovery any O&M expenses for this program, below or above amounts included in rates for the test year. The request would avoid a potential budgetary impact on important programs in order to cover the required staking volume costs. It would also prevent customers from paying for costs that were not incurred if staking volumes are below forecasted levels.

Q. Please describe the change in the Company's standard labor rate and volume increase.

A. The projection for Company labor is primarily based on the projected hours for each year. Increases in labor also reflect projected gas distribution worker hourly standard labor rates. The table below shows historic and projected volumes and hours for Company crews.

Table 33

OM&C Labor Breakdown – Advanced Locating & Inspections		
Year (Jan-Dec)	**Units/Orders**	**Hours**
2017	2,771	7,262
2018	2,988	7,281
2019	10,390	13,739
2020	2,366	10,933
2021	11,168	14,877
2022	2,298	8,962
2023	2,692	9,033
2024 Projected	3,436	9,197
2025 Projected	3,453	10,704
2025-2026 Test year	3,606	11,180

Gas distribution worker hourly standard labor rates are expected to be:

Table 34

Distribution ($/hr)				
	Standard Labor Rates	**Indirect Labor Rates**	**Vehicle Rates**	**Total Rate**
2023	$69.86	$37.72	$43.31	$150.90
2024	$73.41	$39.64	$33.77	$146.82
2025	$75.58	$40.81	$40.81	$157.21
2026	$78.47	$42.37	$42.37	$163.22

Q. Why did the Company initially implement the Dedicated Contractor staking strategy?

A. The Company's Dedicated Contractor staking strategy is to hire a contractor that is dedicated to staking only the Company's gas and electric assets. This was originally implemented in a limited portion of the Company's gas service territory because changes in the program were necessary to improve timeliness and accuracy of staking for public safety, especially given the continued ticket volume. Consumers Energy and the State of Michigan are in the fourth quartile for third-party gas distribution damages per

1,000 tickets. When accuracy and timeliness of staking are off target, this creates negative behaviors with third-party excavators, resulting in unsafe digging practices. A critical step in ensuring safe digging practices is having excellence in stake-and-locate timeliness and accuracy.

With a Dedicated Contractor staking strategy, the Company is looking to achieve the following key pillars in support of safe digging and the excavating community.

- The first key objective is *timeliness*. Through the dedicated workforce, the Company will see improved timeliness compared to historical performance to support the excavating community. This will be achieved by having a single utility focus for ticket management. This model improves the ability to manage ticket volume fluctuations throughout the year due to not having the risk of completing all other commitments on the ticket in the shared resource model.
- Another key objective is *quality*, with improved staking accuracy performance compared to recent historical data. This is expected to be achieved as stakers need only focus on one utility type, compared to the shared resource model, where stakers are responsible for all assets (electric, gas, communications, water). This will lead to increased staking proficiency.
- The last key objective is *improved excavator communications* on projects. Improved communications with the excavating community will be enabled by use of enhanced positive response, which provides additional information and pictures to the ticket initiator, and an additional payment type for 180-day project tickets to assist in mitigating the risk of rushing.

Q. Please describe the test year costs for the Dedicated Contractor asset locating program.

A. In the interest of public safety, damage prevention, and in compliance with a facility owner's obligation under Act 174, the act of placing marks to indicate approximate facility location in response to a MISS DIG 811 ticket requested in advance of excavation activity, an anticipated increase in volume and costs are included in the test year projection for gas-only locating. This includes resources to locate *only* gas facilities for Consumers Energy compared to the existing method of vendors locating several other additional external facilities. Additionally, based on the existing benefits realized and lower comparative costs to the Shared Contractor resources, the Company plans to expand the program in 2025 to include all of the Company's statewide gas service territory.

Q. Please describe the Company's plan to expand the Dedicated Contractor staking program.

A. Based on existing benefit realization for the Dedicated Contractor staking program, the Company plans to expand the program to continue to improve public safety, reduce damages, mitigate communication risks with excavators, improve quality, and comply with timeliness requirement within Public Act 174. Beginning February 21, 2023, the Dedicated Contractor staking program covered two-thirds of Oakland County, which is 20% of the total staking tickets. The plan for 2024 has the Dedicated Contractor staking program covering 31% of the total staking tickets. In 2025, the Company plans to expand the Dedicated Contractor staking Program to include the Company's entire statewide gas service territory and cover up to 100% of the total staking ticket volume.

Q. Please explain why the company accelerated the implementation of the Dedicated Contractor staking model to up to 100% of the total ticket volume in 2025.

A. The staking contract with the contractor that the Company uses for its Shared Contractor approach expires in the first quarter 2025. In anticipation, the Company sent out a request for proposal in the third quarter of 2024 for staking services for the Company's remaining gas service territory that at the time was under the Shared Contractor resource model. The request included options for both shared and dedicated services. The bids yielded an average unit cost for the Dedicated Contractor resource model that was below the average unit cost of the Shared Contractor staking model. Based on the lower unit cost, the realized timeliness, and quality improvement from the Dedicated Contractor resource model, the Company plans to pursue the lower cost Dedicated Contractor option and implement a statewide Dedicate Contractor staking approach for its gas service territory for up to 100% of the total staking ticket volume.

Q. Please describe the benefits the Company has seen since implementing the Dedicated Contractor staking program.

A. The Company has seen benefits to overall accuracy, timeliness, and excavator communications on projects since the implementation in February 2023.

In 2023, with the Dedicated Contractor resource model in place, two-thirds of Oakland County (compared to the Shared Contractor resources model in 2022) yielded the following results:

- Accuracy related to at-fault damage reduction improved by 87.3%.
- Field timeliness for the Dedicated Contractor model averaged 98.7% compared to 97.3% for the Shared Contractor resource model in 2023.

For 2024, year-to-date month ending September, the Dedicated Contractor model in place for Oakland and Kent County's compared to the Shared Contractor resources model yielded the following results:

- Accuracy related to at-fault damage reduction improved by 78.6% from 2022.
- Field timeliness for the Dedicated Contractor model averaged 99.5% (including 24 hour re-transmits) compared to 95.2% for the Shared Contractor resource model in 2024.

These results are anticipated to continue due to improvement in staking and locating performance. Additionally, excavator communication on projects has improved through enhanced positive response, which provides an overview of staking and associated pictures to the ticket requester.

Q. Please describe the cost difference between the Shared Contractor resource model and Dedicated Contractor resource model after the RFP.

A. The RFP bids were evaluated using actual 2024 ticket type data with redline and performance incentive adjustments made to provide an accurate comparison between the Shared Contractor resource model and Dedicated Contractor resource model bids. The analysis shows the Dedicated Contractor model is on average $10.90 less on a per unit basis when compared to the Shared Contractor model. Continuing with the Shared Contractor model, and not transitioning to the Dedicated Contractor resource model, would increase program cost by $3,667,000 for the Company's remaining gas service territory in the test year.

Q. Has the Company added communication audits to assist in validating appropriate positive response code utilization as a result of the MPSC Safety Staff's recommendations in the Company's previous gas rate case?

A. Yes. The Company is enhancing communication audits executed by the Company's Damage Prevention Field Liaisons as well as updating timeliness reporting to include county level data in addition to statewide, to assist in identifying incorrect positive response code utilization.

Q. What other activities does the Company perform to reduce dig-in damages besides stake and locate?

A. In addition to the stake and locate program, the Company has a robust damage prevention program that includes damage prevention and public safety liaisons, and public awareness activities.

Damage prevention and public safety liaisons focus on proactive support for the excavating community, including but not limited to training, troubleshooting locating needs, and communications and issues management for all involved stakeholders. The liaisons also play a critical role in the Company's damage investigation program, repeat damager program, and no-call program, where the liaisons follow up on damages in which MISS DIG 811 was not called. Additionally, they perform quality assurance audits on the Company's staking contractors for accuracy in locates. The Company has eight public safety liaisons, with the most recent being a dedicated individual for the gas transmission system due to an increasing number of near misses on the transmission pipelines. The Company has implemented the Irth Solutions UtiliSphere solution as a critical part of the damage prevention 811 ticket management. It enables standardization for field processes and supporting data. It can prioritize tickets and field activities, which help to mitigate the highest risks.

Customer Requested Services

Q. Please describe the O&M expenses related to the Operations & Maintenance – Customer Requested Services sub-program.

A. This sub-program includes the following work activity categories:

- Customer and Company Requested Service activities include Company labor and contractor services for meter and meter stand work, and appliance re-lights after interruptions. Interruptions may be customer driven or related to Company work such as gas facility replacement projects. This category also includes gas meter investigations associated with operational and billing issues.
- Charts and Inspection activities include gas meter inspections and battery exchanges. This work is associated with the metering equipment for commercial and industrial customers. The charts and inspection requirement helps to ensure accuracy in gas flow and utilization.

- Gas Meter Routine activity includes scheduled and companion gas meter exchanges. This work fulfills the Company's Routine Meter Exchange Program. Every year, the Company removes (exchanges) a sample of meters (specific years and types) and tests them for billing accuracy to fulfill MPSC requirements. The number of exchanges required annually is determined according to the testing procedures currently in effect, which specifies how meters are grouped and how many meters of each lot are to be removed and tested annually.

- Meter Work activities including gas turn-ons, turn-offs, investigative tests, as well as setting and removing meters. This work is both emergent and customer committed and is planned based on historical levels; transportation customer meter reads are part of this activity. Also, Smart Energy Advanced Metering Infrastructure ("AMI")/Automated Meter Reading ("AMR") activities were added to the program in 2017 with the implementation of the Gas AMI/AMR project. All activities associated with the gas communication modules are included in this activity, which are investigations, removals, exchanges, and installations of gas communication modules. Deployment has completed, and work has shifted to troubleshooting communication issues with the AMI/AMR meters.

- Non-WBS portion of the sub-program includes labor, internal departmental chargebacks, contractors, and materials not directly associated with a specific work order.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes Contractor labor, credits, and materials for work associated with the activities below.

The historical year costs and projected test year costs for this sub-program are summarized in the following table:

Table 35

Operations & Maintenance – Customer Requested Services		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Non-WBS	$908,747	$1,083,169
Contractor; Materials, Credits and Other Expenses	$339,204	$553,924
Cust Req Services	$4,262,969	$4,501,755
Charts & Inspections	$2,061,833	$2,250,878
Routines	$2,860,814	$3,001,170
Meter Work	$8,443,283	$9,003,511
Total Program	**$18,876,849**	**$20,394,406**

Q. What is the basis for determining the $20,394,406 of O&M expenses in the test year as requested for this sub-program?

A. The costs of the sub-program are primarily driven by Company gas service worker labor, materials, and vehicle expenses. Labor costs consider the amount of jobsite time needed to complete each work activity along with standard labor rates and indirect labor rates for the personnel completing the activity. The Company moved the work type no-gas investigation and repair from this program in 2024 to the Operations and Maintenance – Distribution sub-program. For this sub-program, the units and hours from 2023 to the test year are higher due to the increase in inactive meter removal, routine exchanges associated with rebuilds to top connect stands, and seal for non-pay turn on. Gas Service worker hourly standard labor rates are expected to be:

Table 36

Service ($/hr)				
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2023	$70.23	$105.35	$25.99	$201.56
2024	$73.80	$98.15	$22.14	$194.09
2025	$75.63	$102.86	$22.69	$201.18
2026	$78.52	$106.79	$23.56	$208.86

This historical and projected activity in this program is summarized in the following table:

Table 37

Operations & Maintenance – Customer Requested Services Units/Orders, Hours & Dollars			
Year (Jan-Dec)	Units/Orders	Hours	Dollars
2016	216,935	105,474	$14,468,136
2017	229,333	110,080	$15,410,859
2018	211,300	106,027	$15,885,423
2019	186,242	102,968	$16,711,353
2020	134,870	73,132	$12,113,609
2021	150,212	82,741	$15,519,751
2022	160,647	92,868	$19,198,250
2023	153,649	87,195	$18,876,849
2024 Projected	169,468	87,508	$18,258,562
2025 Projected	173,310	89,816	$19,679,376
2025-2026 Test year	174,514	90,356	$20,394,406

The test year expense projection is based on a weighted average of the 2025 (16%) and 2026 (84%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>Meter First Set Credits</u>

Q. Please describe the Operations & Maintenance – Meter First Set Credits sub-program.

A. The Operations & Maintenance – Meter First Set Credits sub-program offsets the initial labor costs to install a newly purchased natural gas meter (or First Set Cost), and the final labor costs to remove the meter from service prior to retiring and scrapping the meter (or Cost of Removal). Meters are capitalized on purchase, per FERC accounting rules, and these credits offset the installation costs of the meters upon purchase and final disposal of meters.

The Company establishes an annual meter purchase plan for each year in June of the preceding year. That purchase plan provides for meter quantities and types, broken into periodic releases from meter manufacturers throughout the year, to meet all business requirements. Those requirements include new business sets, service upgrades, for-cause exchanges (such as damage, leak, and obsolescence), project work such as Enhanced Infrastructure Replacement Program ("EIRP"), and regulatory testing requirements. Factors considered when establishing the annual plan include current levels of inventory by meter type, assumptions of new business services expected in the coming year, historical for-cause exchange data, project work projections, historical trending for meter retirements, and regulatory program (i.e., the Routine Meter Exchange Program) projections. The plan calls for receiving shipments of meters at different points throughout the year, so the Company can adjust the orders as actual inventories are observed.

Q. What is the basis for determining the $7,959,910 projected O&M credit in the test year?

A. This O&M offset is primarily driven by the purchase of new gas meters. During the test year period, the Company plans to purchase 47,043 new gas meters. The expected credit from these purchases during the test year is $4,419,910. The credit is calculated monthly based on the standard labor rate of employees performing the work, the vehicle loading rate, and the indirect labor costs such as travel time that an employee spends performing their work. This rate is applied to each meter purchased during that month based on the average time required to install the meter to determine the O&M first set credit.

During the test year period, the Company plans to retire 42,000 existing gas meters. The expected credit from these meter retirements is $3,540,000.

The cost of removal credit rate is calculated monthly based on the standard labor rate of employees performing the work, the vehicle loading rate, and the indirect labor costs incurred as employees perform the work. This rate is applied to each meter retired from service during that month based on the average time required to remove the meter from service to determine the O&M cost of removal credit. The annual dollar amount of first set credits is tied directly to the number of units of natural gas meters purchased.

The annual dollar amount of the cost of removal credits is directly tied to the number of units of natural gas meters retired from service during the year. Actual and projected amounts for 2016 through the test year are shown in the table below:

Table 38

Operations & Maintenance – Meter Credits Units/Orders, Hours & Dollars			
Year (Jan-Dec)	**Units Purchased**	**Units Retired**	**Dollars**
2016	73,707	53,518	($4,918,315)
2017	77,380	55,846	($6,782,867)
2018	65,471	50,654	($6,636,758)
2019	61,570	43,207	($7,064,014)
2020	58,997	42,471	($6,810,432)
2021	49,759	38,230	($7,062,668)
2022	20,902	39,631	($5,451,241)
2023	35,200	65,222	($6,942,199)
2024 Projected	43,107	48,480	($8,104,000)
2025 Projected	47,546	42,000	($8,490,090)
2025-2026 Test year	47,043	42,000	($7,959,910)

The test year expense projection is a weighted average of the 2025 (17%) and 2026 (83%) forecast amounts, which reflect the Company's historical experience of program expense timing.

ROW Clearing

Q. Please describe the O&M expenses related to the ROW Clearing sub-program.

A. The ROW Clearing sub-program expenses are needed for clearing and vegetation management for the Company's nearly 2,800 miles of natural gas transmission and storage field pipelines. The Company has historically performed minimum clearing necessary to complete inspections, repairs, replacement of pipe, and limited demand clearing for emergent work.

ROW clearing for gas transmission lines at a cyclical program level began in 2020. The projected test year amount of $2,047,934 will permit the continued clearing and herbicide treatment of approximately 400 miles of transmission line ROW per year.

This will place the natural gas transmission and storage pipeline system on an approximate seven-year clearing cycle to optimize the resources needed to maintain the ROW and prevent the growth of large trees that require hand cutting. A seven-year clearing cycle will allow the Company to create a sustainable integrated vegetation management program to minimize woody vegetation growth. This will also allow the gas transmission ROWs to be maintained at full width, increasing awareness for nearby property owners, and making encroachments on the ROW more visible. This seven-year cycle represents the maximum period between clearings to permit aerial patrol and ground line patrol, leak survey, and identify encroachments. The integrated vegetation management program promotes pollinator species and bird species dependent on early successional habitat, whose populations have been on the decline in the United States due to habitat loss. This additional environmental benefit does not affect the cost of the clearing program.

Table 39

Right-of-Way Clearing		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Salary & Expenses	$219,714	$254,637
Mechanical Clearing Treatments	$1,274,254	$1,476,792
Herbicide Treatments	$273,097	$316,505
Total Program	**$1,767,066**	**$2,047,934**

Q. What is the basis for determining the $2,047,934 of projected O&M expenses in the test year for this sub-program?

A. The projected expenses in this sub-program are primarily driven by the planned miles to be cleared and maintained. In Case No. U-20322, the Company proposed increased funding to implement a vegetation management program with a seven-year clearing cycle.

For the fourth full year of the plan implementation in 2023, the Company spent $1,767,066 and is targeting and on track to spend $1,623,888 in 2024.

The 2024 program includes the continued implementation of the herbicide treatment portion of the integrated vegetation management program, which is offset one year following mechanical clearing treatments. The Company is on track to continue to clear 400 miles annually, including herbicide as part of the integrated vegetation management program for ROW Clearing at the projected test year spending of $2,047,934. The projected cost increase reflects the program theoretically getting on cycle. So rather than continuing to reclaim the ROW as in previous years, the Company's intent is to reach a managing phase of the program. The 2020 actual miles and expense through the test year plan miles and expense are shown in the table below.

Table 40

Right of Way Clearing		
Miles & Dollars		
	Miles	
Year (Jan-Dec)	**Cleared**	**Dollars**
2016	n/a	$86,364
2017	n/a	$535,582
2018	n/a	$1,095,233
2019	n/a	$358,880
2020	412.6	$1,147,835
2021	423.0	$1,844,924
2022	304	$1,827,267
2023	424	$1,767,066
2024 Projected	400	$1,623,888
2025 Projected	400	$1,613,888
2025-2026 Test year	400	$2,047,934

The test year expense projection is a weighted average of the 2025 (9%) and 2026 (91%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Meter Reading

Q. Please describe the O&M expenses related to the Meter Reading sub-program.

A. The Meter Reading sub-program includes Company employee labor, business expenses (such as fleet costs, and training), and technology expenses (hardware and software maintenance, cellular, and system improvements) for purposes of obtaining meter indexes for the calculation of customer bills.

The Company obtains meter indexes by three methods:

1. The mobile collection of meter indexes using AMR equipped vehicles on scheduled routes.
2. The automated collection of meter indexes using the Company's AMI meters.
3. The manual collection of meter indexes by walking up to meter installations to obtain reads.

The Company achieved overall year-end gas meter read rates of 99.76% in 2022 and 99.73% in 2023. The year-end meter reading results for 2022 and 2023 for the various processes used by the Company are as follows:

Table 41

	Meters Available		Meters Read		Meter Read Rate	
Year	**2022**	**2023**	**2022**	**2023**	**2022**	**2023**
Gas AMR	13,699,110	13,787,192	13,685,051	13,767,861	99.90%	99.86%
Gas AMI	8,006,601	8,047,105	7,986,287	8,023,901	99.75%	99.71%
Manual Gas Reads	168,382	159,831	150,886	143,063	89.61%	89.51%

The Meter Reading sub-program is managed jointly for the Company's electric and natural gas operations. As a result, the total meter reading costs are allocated between electric and natural gas. The average gas/electric allocation for the test year is projected to be 39% electric and 61% gas; in 2023, the allocation was split 38.8% electric and 61.2% gas. The difference between the 2023 actual and projected test year electric and gas allocation considers the optimization of AMR and manual routes.

A comparison of the 2023 actual and test year projection is provided below:

Table 42

Meter Reading		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Meter Reader Salaries	$294,822	$317,050
Supervision & Administration Salaries	$1,555,897	$1,673,203
Meter Reading Expenses	$756,696	$813,747
Total Program	$2,607,415	$2,804,000

Q. What is the basis for determining the $2,804,000 of projected O&M expenses in the test year for this sub-program?

A. Spending in this sub-program is primarily driven by Company employee labor, business, and technology expenses. The test year projected expense is $2,804,000, which is an increase of $196,585 because of increased technology fees and annual labor salary increases.

For the test year, the number of gas meter reader operating employees is projected to be 22 employees. These employees will navigate AMR mobile collection vehicles and continue to manually read approximately 14,790 gas meters.

The manual reads occur for the following reasons: opt-out customers (Opt Out Not Cut Over), out of scope meters (i.e., commercial/industrial meters) (Not Cut Over), and rate not eligible accounts (Rates ineligible).

The table below shows this breakdown as well, separated between Legacy and Smart meter customers:

Table 43

August 2024	
Gas Customers Not Cut Over To AMI/AMR	
Description	**Manually Read Meters Count**
Legacy Not Cut Over	4,162
Legacy Opt Out Not Cut Over	5,293
Legacy Rates Ineligible for GCM	2,649
Total Legacy Not Cut Over	**12,104**
GCM AMR Not Cut Over	941
GCM AMR Opt Out Not Cut Over	0
GCM AMR Rates Ineligible	903
GCM AMI Not Cut Over	608
GCM AMI Opt Out Not Cut Over	0
GCM AMI Rates Ineligible	160
Total Smart Not Cut Over	**2,612**
GRAND TOTAL NOT CUTOVER	**14,716**

The following table provides the actual meter reading O&M cost for 2016 through 2023, as well as forecasted amounts for 2024 through the test year:

Table 44

Meter Reading		
Equivalent Staffing & Dollars		
Year (Jan-Dec)	**Average Gas Staff**	**Dollars**
2016		$13,582,033
2017		$12,328,228
2018	112	$10,499,528
2019	67	$7,633,272
2020	31	$4,097,383
2021	23	$2,830,688
2022	22	$2,592,247
2023	22	$2,607,415
2024 Projected	22	$2,567,867
2025 Projected	22	$2,624,385
2025-2026 Test year	22	$2,804,000

The expense projection for the test year is a weighted average of the 2025 (17%) and 2026 (83%) forecast amounts, which reflect the Company's historical experience of program expense timing.

__**Meter Technology and Management System Support**__

Q. Please describe the O&M expenses related to the Meter Technology and Management System Support sub-program.

A. The Meter Technology and Management System Support sub-program ensures the safety, accuracy, maintenance, and stability of the Company's natural gas metering equipment. This program supports the verification of meter accuracies for all customer classes. The program costs are associated with testing and refurbishing gas meters, instrument correctors, gas communication modules, and regulators in response to the Company's Routine Meter Exchange Program.

In July of 2020, the Company combined the Meter Technology Center ("MTC") and the Smart Energy Operations Center ("SEOC") into one combined operation. The

SEOC Program includes the gas portion of the labor and expenses relating to the SEOC daily responsibilities in connection with obtaining AMR meter reads. This includes troubleshooting the equipment, order creation, and IT system demand requirements.

The SEOC is responsible for the reliability and data delivery of the AMI electric meters and AMR gas communication modules. Electric-related costs are not included in this filing. The SEOC benefits customers by providing actual meter reads, minimizing the number of estimated bills, and providing reliable and timely data through daily AMI and monthly AMR meter interrogations.

The 2023 historical expense and the test year projected expense are summarized in the following table:

Table 45

Meter Tech & Mgmt Sys Support		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Exempt/Non-Exempt Salaries	$206,101	$224,490
OM&C Salaries	$740,763	$806,857
Expenses	$338,454	$368,652
Meter Correctors (began to purchase as O&M in 2022)	$246,460	$2,598,000
Total Program	$1,531,778	$3,998,898

Q. What is the basis for determining the $3,998,898 projected O&M expenses in the test year for this sub-program?

A. This sub-program expense is primarily driven by labor, operating, and material costs.

In 2021, a determination was made relative to stand-alone natural gas meter correctors, which had previously been purchased under the Gas Meters capital program, that the components were considered replacement parts and would be purchased under the O&M program going forward, starting in 2022. The change in purchasing instrument correctors in this program represents a $2,598,000 impact in the test year, purchasing 2,190 stand-alone units. The test year projected program requirement represents normal business expenses with the change in categorization of the gas meter corrector purchases. The following table provides the actual O&M cost for 2016 through 2023, as well as forecasted amounts for 2024 through the projected test year:

Table 46

Meter Tech & Mgmt Sys Support Dollars			
	Labor	Other	Total
Year (Jan-Dec)	Dollars	Dollars	Dollars
2016	$1,198,957	$67,162	$1,266,120
2017	$1,218,563	$64,613	$1,283,175
2018	$1,265,965	$82,867	$1,348,832
2019	$1,227,567	$85,006	$1,312,573
2020	$1,040,289	$45,134	$1,085,423
2021	$1,055,672	$213,094	$1,268,766
2022	$1,106,459	$320,326	$1,426,785
2023	$950,010	$581,768	$1,531,778
2024 Projected	$1,048,202	$1,059,850	$2,109,560
2025 Projected	$1,119,870	$2,711,130	$3,831,000
2025-2026 Test year	$1,031,348	$2,967,550	$3,998,898

The test year expense projection is a weighted average of the 2025 (19%) and 2026 (81%) forecast amounts and reflect the Company's historical experience of program expense timing.

Smart Energy Metering Technology Center

Q. Please describe the O&M expenses related to the Smart Energy Metering Technology Center sub-program.

A. The Smart Energy Metering Technology Center sub-program includes:

(i) The gas portion of expenses related to software maintenance for gas communications modules installed on locations in which the module communicates data through the electric meter.

(ii) The gas portion of the cellular communication expenses allocated to gas communication modules that pass data through the electric meter.

(iii) The gas portion of a technical support contract with the Company's AMI/AMR vendor.

These costs are contractually based through 2032 on a per meter or communication module basis.

Table 47

Smart Energy MTC – Gas		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Communication Charges	$250,982	$255,609
GCM Software Maintenance	$167,860	$170,954
Technical Support Services Contract	$125,000	$127,304
Total Program	$543,842	$553,867

Q. What is the basis for determining the projected O&M expenses in the test year for this sub-program?

A. The projected expense is based on the number of units of AMI-programmed gas modules installed in the field and in inventory to support operations.

With the completion of deployment, the AMI gas module population, subject to a portion of the cellular and software maintenance expenses, has stabilized at a level to include all installed meters and inventory required to support new installations going forward. This should also provide for replacement of existing meters for cause (an error/malfunction) or routine exchange requirements. In addition, per the contract that runs through 2032, the software maintenance expense per unit increases 3% per year. Actual and projected amounts for 2016 through the test year, are shown in the table below:

Table 48

Smart Energy MTC – Gas Dollars	
	Total
Year (Jan-Dec)	Dollars
2016	0
2017	$846,677
2018	$598,586
2019	$606,147
2020	$542,619
2021	$565,536
2022	$542,948
2023	$543,842
2024 Projected	$554,888
2025 Projected	$553,867
2025-2026 Test year	$553,867

The test year expense projection is a weighted average of the 2025 (13%) and 2026 (87%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>Gas Storage</u>

Q. Please describe the O&M expenses related to the Gas Storage sub-program.

A. Gas Storage sub-program O&M expenses are directly associated with various maintenance and operational tasks purposed to ensure the predictable and safe operation of the natural gas storage system. The natural gas storage system includes 15 gas storage fields, 808 gas storage wells, and 244 miles of gathering lines, with associated valving, conditioning systems, and access roads. The program funds critical tasks associated with operability and regulatory compliance. Tasks that are executed annually through this sub-program include valve and operator inspections, line patrol and leak survey, integrity monitoring, inspection and maintenance of regulators and relief valves, surface and subsurface safety valves, isolation valves, fluid separators, and fluid disposal systems. In addition, the Gas Storage O&M sub-program ensures near real-time emergency response preparedness.

This sub-program includes the following work activity categories:

- Non-WBS portion of the sub-program includes labor, internal departmental chargebacks, contractors, and materials not directly associated with a specific work order.

- Contractor Materials, Credits and Other Expenses portion of the sub-program includes contractor labor, credits, and materials for Code Inspection, Facilities Locating for Third Parties (MISS DIG 811), Demand/Preventive/Compliance Maintenance and Operations which are directly associated with a specific work order.

- Code inspections and compliance work is in adherence to all applicable local, state, and federal laws, including those implemented by the MPSC, EGLE, PHMSA, Environmental Protection Agency, Bureau of Land Management, and Michigan Occupational Safety and Health Administration. Regulatory Maintenance activities include pigging activities, corrosion prevention, dehydrator and separator preventative maintenance, valve and operator inspection and repair, access road maintenance, regulator and relief inspections, pipeline patrol, and leak survey to ensure public safety.

- Operation and integrity work includes the bi-annual pressure survey of all 15 fields for reservoir integrity and inventory verification, monthly wellhead pressure monitoring to ensure asset integrity and deliverability, configuring of gas storage fields for injection/withdraw cycles, and routine inspection of assets during winter operations/peak demand.

- Demand maintenance has trended consistent historically. Drivers of these costs include gas storage well intervention, integrity demonstration, and issues affecting gas flow deliverability. This may include well intervention, well logging, freezes in pipelines, snow plowing to ensure access facilities, and response to periodic equipment and system failures requiring intervention and corrective measures to maintain reliability and public safety.

The historical year costs and projected test year costs for this program are summarized in the following table:

Table 49

Gas Storage O&M		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Non-WBS	$1,699,628	$1,456,458
Contractor; Materials, Credits and Other Expenses	$909,821	$910,911
Code Inspections	$1,559,900	$1,548,457
Facilities Locating for Third Parties (MISS DIG 811)	$828,615	$822,537
Demand/Preventive/Compliance Maintenance	$890,681	$884,147
Operations	$53,032	$52,643
Less: Facility Chargebacks	($202,567)	($202,567)
Total Program	$5,739,110	$5,472,586

Q. **What is the basis for determining the $5,472,586 of projected O&M expenses in the test year for this sub-program?**

A. The projected expense for this sub-program is historically based, and primarily driven by known units (labor hours) and historical actuals execution of tasks associated with the following activities: compliance inspections, maintenance inspections, operation of the gas storage facilities to meet gas flow deliverability needs and third-party damage prevention tasks (such as locate/stake, crossings, and contractor oversight) to ensure public safety, code compliance, maintenance of critical assets, and operation of the system to deliver natural gas across the state.

These tasks include monthly well site visits and operational support of the Annular monitoring program, including well intervention. Gas transmission worker hourly standard labor rates are expected to be:

Table 50

Transmission ($/hr)				
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2023	$69.18	$24.90	$36.67	$130.75
2024	$72.53	$23.93	$34.81	$131.28
2025	$76.37	$26.73	$32.08	$135.17
2026	$79.28	$27.75	$33.30	$140.33

The historical and projected activity in this sub-program are summarized in the following table:

Table 51

Gas Storage O&M Dollars	
Year (Jan-Dec)	Dollars
2016	$7,062,022
2017	$5,667,339
2018	$6,305,807
2019	$6,187,826
2020	$5,821,338
2021	$5,860,452
2022	$6,338,065
2023	$5,739,110
2024 Projected	$5,355,743
2025 Projected	$4,771,940
2025-2026 Test year	$5,472,586

The test year expense projection is a weighted average of the 2025 (12%) and 2026 (88%) forecast amounts, which reflect the Company's historical experience of program expense timing. The test year expense is lower due to the following factors: maintenance is decreasing due to abandonment of some facilities (wells), and increased compliance inspections leading to less equipment-related failure.

<u>Replace Vintage Services</u>

Q. Please describe the O&M expenses related to the Replace Vintage Services ("RVS") sub-program.

A. The O&M expenses for RVS sub-program occur because a small percentage of planned capital RVS orders are not able to be completed as planned.

Reasons for these orders not being completed include field crew identification of services that are already plastic, construction barriers such as service connections to mains that exist under construction barriers such as poles or trees, field crew identification of forced sewer facilities, meters that are not reasonably accessible, excessive main depth, high ground water conditions, evidence of other underground facilities that were unable to be located, and orders for branch services that do not qualify as capital assets.

The historical year costs and projected test year costs for this program are summarized in the following table:

Table 52

Replace Vintage Services		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Replace Vintage Services	$13,897	$70,926
Total Program	**$13,897**	**$70,926**

Q. What is the basis for determining the $70,926 of projected O&M expenses in the test year for this sub-program?

A. The forecast for 2025 and 2026 anticipates that a small percentage of RVS construction orders will be returned from the field as non-constructible. The Company plans to replace

4,164 services in 2025 and 5,913 services in 2026. The expected non-constructible rate is expected to be 1.30% of planned units.

The historical and projected activity in this sub-program is summarized in the following table:

Table 53

Operations & Maintenance – Replace Vintage Services Units/Orders, Return Rate & Dollars			
Year (Jan-Dec)	**VSR Planned Units**	**Return Rate**	**Dollars**
2016	NA	NA	NA
2017	6,307		$1,324
2018	9,381		$102,593
2019	5,571		$90,072
2020	5,456		$83,994
2021	5,056	1.25%	$298,453
2022	2,176	1.25%	$98,417
2023	1,228	1.4%	$13,897
2024 Projected	2,424	1.30%	$70,289
2025 Projected	4,164	1.30%	$70,289
2025-2026 Test year	5,913	1.30%	$70,926

The test year expense projection is a weighted average of the 2025 (36%) and 2026 (64%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>**Gas Operations Field Operations**</u>

Q. Please describe the O&M expenses related to the Gas Field Operations sub-programs shown on Exhibit A-88 (JPP-3).

A. The Gas Field Operations sub-programs includes training for approximately 1,500 natural gas field operations employees.

Also included is training for the Company's gas construction workforce, small tools, natural fiber clothing, safety equipment, field operation expenses, labor and expenses for personnel who are responsible for statewide scheduling and assignment of requested work, and management and administrative personnel of Gas Operations to ensure the safe and effective operation of the gas facilities.

Training

Q. Please describe the O&M expenses related to the Training sub-program.

A. The Training sub-program includes training for approximately 1,500 natural gas field operations employees, including Operator Qualification ("OQ") training, in accordance with applicable regulations. Examples of training provided under this sub-program include equipment operator, pipe joining, valve inspection and maintenance, welding, and pressure control (regulation).

Safety training is also included in this program, which drives improved safety performance in gas field operations. Gas field operations employees receive training each year to ensure a highly skilled workforce qualified to safely operate, maintain, and execute the tasks necessary to meet customer and work demands.

The historical year costs and projected test year costs for this program are summarized in the following table:

Table 54

Operation & Maintenance – Training Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Gas Operations OM&C Training	$4,330,190	$4,507,764
Athletic Trainers	$313,140	$245,045
Gas Training Non-Labor Expense	$92,353	$91,440
Total Program	**$4,735,683**	**$4,844,249**

Q. What is the basis for determining the $4,844,249 of projected O&M expenses in the test year for this sub-program?

A. Spending in this sub-program is primarily driven by the hours of training conducted for Gas Operations employees. This training is required to ensure a skilled and qualified field operations workforce is available that can complete all customer-requested and compliance-based tasks.

The historical and projected activity in this program is summarized in the following table:

Table 55

Training Hours & Dollars		
Year (Jan-Dec)	**Training Hours**	**Dollars**
2016	77,351	$5,141,541
2017	74,539	$5,718,735
2018	100,790	$6,786,833
2019	83,324	$6,145,865
2020	50,033	$4,698,219
2021	85,722	$6,246,682
2022	83,518	$6,205,592
2023	73,753	$4,735,683
2024 Projected	60,679	$4,150,817
2025 Projected	68,430	$4,607,108
2025-2026 Test year	69,749	$4,844,249

The test year expense projection is a weighted average of the 2025 (14%) and 2026 (86%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>Tools</u>

Q. Please describe the O&M expenses related to the Tools sub-program.

A. The Tools sub-program includes the acquisition of small tools, natural fiber clothing, and safety items for field employees.

This ensures employees complete field work in a safe, efficient, and effective manner. Natural Fiber clothing is a required personal protective equipment provided by the Company for employees in the field and who may be exposed to an area where natural gas is present.

Tools included in this sub-program are small hand tools, and any tool used in the field that had an original cost of less than $1,000. Fusion equipment, drills, grinders, and clamps are examples of tools that would be purchased under this program.

Q. What is the basis for determining the $1,431,000 of projected O&M expenses in the test year for this sub-program?

A. The projected expense for this sub-program is based on historical levels as well as any known work plan needs and headcount changes for the test year period. The historical and projected activity in this program is summarized in the following table.

Table 56

Tools	
Dollars	
Year (Jan-Dec)	**Dollars**
2016	$1,805,705
2017	$1,938,712
2018	$2,136,931
2019	$1,702,554
2020	$1,785,981
2021	$1,691,000
2022	$3,065,612
2023	$1,827,711
2024 Projected	$1,438,372
2025 Projected	$788,998
2025-2026 Test year	$1,431,000

The test year expense projection is a weighted average of the 2025 (16%) and 2026 (84%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>Field Operations</u>

Q. Please describe the O&M expenses related to the Field Operations Expenses sub-program.

A. The Field Operations Expenses sub-program includes operating employee expenses, telephone/computer chargebacks, environmental fees, gas pipeline user fees, transmission flight operations (aerial surveys), and other miscellaneous expenses.

Primary drivers for this sub-program's expenses are operating employee miscellaneous expenses, pipeline user fees, and permits. Operating employee miscellaneous expenses include items such as costs for mileage, hotels for Company-related trips, permit fees, and telephone and computer charges.

Pipeline user fees are fees paid to the PHMSA section of the United States Department of Transportation for gas distribution and gas transmissions lines. Details regarding the actual O&M expenses in 2023 and the projected test year expenses are provided in the table below:

Table 57

Field Operations Expenses		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Field Ops OM&C Gas Expenses	$1,752,881	$1,433,578
Field Ops OT Meals Gas	$287,835	$320,088
Pipeline User Fees	$696,966	$847,620
Permits	$95,831	$74,640
Gas Field Mobility Exp	$294,525	$347,922
Gas Bonds	$334,514	$600,000
Total Program	**$3,462,552**	**$3,623,848**

Q. What is the basis for determining the $3,623,848 of projected O&M expenses in the test year for this sub-program?

A. The projected test year expense in this sub-program is based on historical spend levels as well as any known work plan needs for the test year period. The reason for this increase in spending is driven primarily by increased bond purchase costs.

Table 58

Field Operations Expenses Dollars	
Year	**Dollars**
2016	$4,070,748
2017	$4,039,347
2018	$3,223,396
2019	$3,133,706
2020	$2,964,197
2021	$3,709,349
2022	$3,899,805
2023	$3,462,552
2024 Projected	$3,776,000
2025 Projected	$2,727,234
2025-2026 Test year	$3,623,848

The test year expense projection is a weighted average of the 2025 (9%) and 2026 (91%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Indirect Labor/Labor Variation

Q. Please describe the Indirect Labor/Labor Variation O&M Expense.

A. The Indirect Labor/Labor Variation expense supports the difference between the Company's actual operating employees' wages and the amount of salary cost allocated to work orders, using standard labor rates. Indirect Labor Variation occurs when the Company has labor costs not directly related to a work order, such as travel time between jobs, that has not been allocated to a work order via the indirect labor loading. The Company attempts to clear these account balance variances by year end. Thus, the Company does not project any test year expense in this sub-program.

<u>Supervision/Admin Staff</u>

Q. Please describe the O&M expenses related to the Supervision/Admin Staff sub-program.

A. The Supervision/Admin Staff sub-program provides for the management and administrative personnel for Gas Operations to ensure the safe and effective operation of the gas facilities. Operational supervision helps ensure the safety of crews working in the field as well as the safe execution of work practices.

This section combines the Supervision/Admin Staff - Distribution, Supervision/Admin Staff - Services, and Supervision/Admin Staff - Transmission & Storage sub-programs that are shown individually on Exhibit A-88 (JPP-3) page 1, lines 5, 6, and 7.

Q. What is the basis for determining the $5,811,757 of projected O&M expenses in the test year for this sub-program?

A. The projected expense in this sub-program is primarily driven by labor and expenses. In 2021, this program only included employees from Gas Service and Gas Distribution. During 2022, Gas Transmission and Storage, which encompasses M&R and Pipeline, was added to this sub-program.

In September 2023, the Gas Operations Support and Gas Contractor Oversights Teams, formerly part of the Operations Compliance and Controls sub-program, were added to this sub-program. These departments consist of the following areas focused on enhancing the Company's compliance to regulatory requirements and ensuring proper controls.

The following functions were added to the sub-program:

- OQ and the gas operations certification training program ensure the Company's field workforce is qualified to perform its work obligations on the gas system.

- Management of the Company's operational compliance quality assurance processes and systems for identification of risks and opportunities across the Company's gas facilities and operations. This is accomplished through the implementation of preventative and detective controls to manage compliance with state and federal regulatory requirements and an effectiveness verification approach.

- Contractor oversight and management for construction contractors performing work on behalf of the Company on the gas system. This also includes expenses for technology and standardization to achieve remote inspection, governance around contractor oversight, and sewer/cross bore program.

Effective in 2023, the Distribution program includes the labor, expenses, and chargebacks for these employees. The historical year costs and projected test year costs and headcounts are summarized in the following table:

Table 59

Year (Jan – Dec)	Distribution Headcount	Service Headcount	T&S Headcount	Total Headcount	Dollars
2021	151	NA	27	178	$6,819,841
2022	102	48	24	174	$5,345,649
2023	117	47	15	179	$5,576,984
2024 Projected	115	45	18	178	$5,515,440
2025 Projected	115	46	18	179	$5,676,659
2025-2026 Test year	115	46	18	179	$5,811,757

Headcount is expected to be flat from 2023 through the test year. The test year expense projection for the test year is a weighted average of the 2025 (17%) and 2026 (83%) forecast amounts, which reflect the Company's historical experience of program expense timing.

Dispatch & Scheduling

Q. Please describe the O&M expenses related to the Dispatch & Scheduling sub-program.

A. The Dispatch & Scheduling sub-program includes the labor and expenses for personnel who are responsible for efficiency and consistency in statewide scheduling and assignment of emergent, compliance, and customer requested work.

The Dispatching function operates 24 hours per day, 365 days per year in three locations across the state. The Scheduling and Meter Reading support operates during normal business hours and the associated overtime hours as work volume fluctuates throughout the year.

Emergent work consists of odor response investigations, emergent leak repairs, and third-party damage response and repair.

Compliance work consists of work order coordination, creation, and assignment of gas meter routine exchange program, and planned leak and non-leak maintenance work.

Customer-requested work consists of meter turn on/off, seal for nonpayment turn on, issue investigations, and meter upgrades.

This sub-program is also responsible for assigning meter reading routes to technicians and associated troubleshooting. Additionally, it is also responsible for the gas meter Consecutive Estimate Program, which manages customer accounts (approximately 1,000) with three or more consecutive estimates through an escalation process. Escalation includes tracking and reporting of accounts, manual and automated phone calls, postcard and letter mailings, scheduling of appointments, and coordination with other departments and customers to resolve meter access issues. The actual O&M expenses in 2023 and the projected test year expenses are provided in the table below:

Table 60

Dispatch and Scheduling		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Dispatch and Scheduling	$1,179,714	$1,278,488
Total Program	$1,179,714	$1,278,488

Q. What is the basis for determining the $1,278,488 for Scheduling and Dispatch expenses in the test year for this sub-program?

A. The projected expense in this sub-program is primarily driven by customer-requested demand, including short cycle demand, such as emergency and service calls in addition to gas meter reading work assignment and Consecutive Estimate Program activities. Response to customer and emergent demand requires appropriate levels of personnel to plan, schedule, and dispatch the associated work. This sub-program includes the labor costs and expenses for these personnel.

In 2021, this financial program was separated from a larger program with responsibility for the identified work activities and long cycle work planning, scheduling, and closeout.

Table 61

Dispatch and Scheduling Dollars	
Dollars	
Year	**Dollars**
2016	n/a
2017	n/a
2018	n/a
2019	n/a
2020	n/a
2021	$1,465,488
2022	$1,371,650
2023	$1,179,714
2024 Projected	$1,101,852
2025 Projected	$1,239,000
2025-2026 Test year	$1,278,488

The test year expense projection is a weighted average of the 2025 (16%) and 2026 (84%) forecast amounts, which reflect the Company's historical experience of program expense timing.

EIRP

Q. Please describe the O&M expenses related to the EIRP sub-program.

A. These expenses include training for the Company's gas construction workforce, salaries and expenses for the field supervisors and managers, tools, and facilities maintenance. These expenses ensure that the seasonal workforce is properly staffed, trained, and has the necessary tools and facilities.

Table 62

EIRP O&M		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
EIRP Supervision & Admin Sal/Exp	$869,933	$685,299
EIRP Tools	$84,056	$41,757
EIRP OM&C Expenses (Non-Labor)	$10,059	$260,140
EIRP Facilities	$251,148	$271,422
EIRP Labor OM&C Training	$2,132,942	$3,789,331
Total Program	**$3,348,137**	**$5,047,949**

Q. What is the basis for determining the $5,047,948 of projected O&M expenses in the test year for this sub-program?

A. Approximately 75-80% of the expense in this program is the technical training required to ensure the field employees are fully skilled and qualified to complete the EIRP work. This includes initial training for newly hired employees, as well as more advanced training for higher skilled employees. Along with technical training, expenses in this sub-program include annual refresher training covering standards and policy changes, along with safety procedural changes.

The EIRP workforce is one of the largest hiring groups in the Company to meet the demand of the total gas construction activities (including gas asset replacement and relocation programs as well as the Infrastructure Replacement Program). The EIRP workforce continues to experience employees transferring to other operating departments within the Company.

Along with this employee movement, hiring and training are planned to allow for appropriate staffing as the Company implements the NGDP. Based on projections, this will result in increased spending compared to 2023. This increase is due to additional training needed for the complexity of the EIRP work plan, and for training new hires to maintain the workforce. As the NGDP progresses, this level of staffing and training is expected to moderate.

In addition to training field personnel, this program also equips those employees with necessary tools and facilities. Facility expenses largely consist of the eight Headquarters sites for the group (located in Saginaw, Lansing, Livonia, Macomb, Flint, Midland, Jackson, and Royal Oak). These costs are driven by the planned work activities that are based on the amount of vintage pipe to be replaced. The facility expenses also include the O&M portion of the total lease payment for the facilities. Lease payments are discussed in the testimony of Company witnesses Kristine A. Pascarello and Quentin A. Guinn. This program expense also experiences inflationary effects as nearly all sites are leased or rented.

Leadership oversight of the approximately 550 field employees, including contractors, in the EIRP workforce is necessary to ensure regulatory compliance, provide instruction for field employee training, and confirm OQs are in place. The projected test year costs for this function are consistent with historical expenses. The historical and projected cost summary is shown in the below table:

Table 63

EIRP O&M Dollars	
Year (Jan-Dec)	**Dollars**
2016	$2,309,424
2017	$2,415,780
2018	$1,996,035
2019	$2,496,230
2020	$5,462,735
2021	$3,681,670
2022	$4,370,398
2023	$3,348,137
2024 Projected	$3,051,022
2025 Projected	$3,367,718
2025-2026 Test year	$5,047,948

The test year expense projection is a weighted average of the 2025 (6%) and 2026 (94%) forecast amounts, which reflect the Company's historical experience of program expense timing.

<u>**Work Management and Customer Delivery**</u>

Q. Please describe the expenses related to the Work Management and Customer Delivery O&M Program shown on Exhibit A-89 (JPP-4).

A. The Gas Operations Performance ("Ops Performance") Department represented a department within the Consumers Energy Operations organization that began in 2017. The Ops Performance team included experts in work planning, project management, scheduling, administration, data analytics, data science, Lean Operating Systems, process engineering, industrial engineering, standards management, and technology. This department consisted of the following functions focused on streamlining processes to achieve first-time quality for our customers:

(1) Work Management Excellence,

(2) Process, Analytics & Technology, and

(3) Industrial Engineering.

In 2024, the Process, Analytics & Technology, and Industrial Engineering departments moved to other organizations within the Company. The Work Management Excellence department remained and was renamed Work Management and Customer Delivery. Their function is described below.

- Work Management and Customer Delivery includes functions for Distribution Planning, Scheduling, Close-Out, Statewide Admin, and Customer Energy Management (CEM) for long-cycle work. Long-cycle work includes new business requests, gas facility relocates, planned maintenance, alterations, demolitions, gas leak repair, and capacity/augmentation.
    - Planning ensures the operating plan adheres to the MPSC-approved business plan for Gas Operations field work.
    - Scheduling ensures field crews have enough work, ready-work, and the right work and resources to complete the work plan.
    - The Close Out and Admin functions ensure technical documentation is accurate and complete, and that the costs of the work settle appropriately to the work orders and comply with Sarbanes-Oxley rules for capital and O&M work.
    - In addition to Planning, Scheduling, Close-Out, and Admin functions, the Work Management and Customer Delivery Team assumed responsibility, costs, and headcount of the Customer Energy Management ("CEM") team from Gas Engineering in 2023 and retained Operations Process and Technology functions.
    - The CEM team is focused on meeting customer needs by providing a single point of contact for customer-requested main, service, and meter installations and alterations. CEM is responsible for ensuring all new customer service requests and customer-requested alterations on the Company's distribution system are coordinated from initiation through completion to meet customer expectations.
    - Within CEM, there are four departmental areas of focus.
        - The Zonal Project Coordination team is responsible for customer interaction and project coordination for all new business gas main extensions in their respective geographical region.

- The Gas Customer Attachment Program ("CAP") team coordinates the completion of projects which expand the natural gas system into areas that are just adjacent to the current system limits, where more concentrated pockets of potential customers are located, and administration of CAP project tracking and CAP payments. Even with the conclusion of proactive CAP main installation in 2019, this team remains intact to facilitate the tracking of projects and administer the CAP payments associated with the previously installed mains and services per the tariff requirements.

- The CEM team is also responsible for "Express Design" services for all residential service requests within subdivisions, workload coordination and balancing, as well as other design support related tasks, including billing, permitting, and inspection. This organizational re-alignment has aligned like work with like work and provides efficiencies in the work management process.

- The Operations Process and Technology teams provide support for process improvement, standardization, and systems used by Gas Operations, for functions such as project management, scheduling, work management, field order management, field call-out, and meter reading. These resources provide subject-matter expertise, performance coaching, documentation, change management, and technology analysis for changes across the work management process to improve the customer experience.

Table 64

Work Management and Customer Delivery		
Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Work Management and Customer Delivery	$3,005,111	$2,539,000
Total Program	**$3,005,111**	**$2,539,000**

Q. What is the basis for determining the projected $2,539,000 O&M expenses in the test year for this program?

A. The projected expense is primarily the salary and expenses for this team, and other associated costs (such as vendor costs) in support of the Company achieving the objectives previously discussed. To ensure affordability, the Work Management and Customer Delivery program estimates stable costs through the test year, absorbing increases for inflation. The historical and projected head count and cost summary for this program is shown in the below table.

Table 65

Work Management and Customer Delivery O&M Headcount & Dollars		
Year (Jan-Dec)	**Headcount**	**Dollars**
2021	285	$3,211,000
2022	244	$4,955,000
2023	382	$3,005,111
2024 Projected	331	$2,320,246
2025 Projected	331	$2,502,146
2025-2026 Test year	331	$2,538,660

<u>**Gas Operations Management**</u>

Q. Please describe the expenses related to the Gas Operations Management O&M Program shown on Exhibit A-89 (JPP-4).

A. The Gas Operations Management Program includes salaries and expenses for Gas Operations executive level management, Gas Operations support for supply chain and material handling, real estate services that support Gas Operations land ROW, leasing, and Company buildings, and environmental support for contaminated soil testing and clean-up, asbestos assessments and removal, and environmental spills testing and clean-up.

Table 66

Gas Operations Management O&M Projection Breakdown by Activity Type		
Work Type	**2023 Actual**	**2025-2026 Test year**
Gas Operations Management	$834,000	$1,668,000
Total Program	**$834,000**	**$1,668,000**

Q. What is the basis for determining the projected $1,668,000 O&M expenses in the test year for this program?

A. The 2023 actual expense for the Gas Operations Management Program was$834,000. The historical actual amount of program expense is detailed by labor and various non-labor expense components in Exhibit A-89 (JPP-4), page 1, line 3, column b.

The Company's projected test year expense is $1,668,000, as shown on Exhibit A-89 (JPP-4), page 2, line 3, column (j). The projected test year increase from 2023 actual expense is primarily the result of an increase of labor costs to this program. The historical and projected cost summary is shown in the below table:

Table 67

Gas Operations Management O&M Dollars	
Year	**Dollars**
2016	$2,195,460
2017	$922,551
2018	$964,737
2019	$1,212,544
2020	$1,943,237
2021	$1,580,115
2022	$2,094,000
2023	$834,000
2024 Projected	$1,700,542
2025 Projected	$1,643,461
2025-2026 Test year	$1,668,023

IT PROJECTS

Q. Is the Company planning IT projects that support the engineering, asset planning, design, construction, and maintenance of a safe, reliable, and affordable natural gas distribution system for its customers?

A. Yes. Company witness Stacy H. Baker includes in her direct testimony and exhibits a number of technology projects that are critically important in supporting these gas functions within the Company. The expenditures for these projects are contained within the exhibits sponsored by Ms. Baker. The project providing customer benefits for the areas which I am sponsoring are described below:

- The **Standard Work Plan** project requires $137,388 in O&M in the test year.

  Description: The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time-consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the completion of pull-ahead work resulting in unnecessary OT and contractor expense. Implementing a centralized planning platform that will interface with existing systems like SAP, DAPP, and EAM Dashboard would transform our planning organization, offering a clear view of planned work and ensuring that executed work is aligned with strategic objectives. In addition, a more integrated system that leverages automation and real-time data analytics would allow for the immediate, what-if scenario planning the business needs to support sound, data-driven decision-making. The tool, alongside necessary process and system enhancements will streamline the workflow and ultimately lead to schedule quality and ensure prudent overtime and contractor usage through reducing the amount of unplanned work breaking into the work management process. A shift to a digital solution that fully aligns resources, work units and feeds the schedule will represent a significant step forward in resource management, aligning with modern best practices.

  Problem Statement: The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time-consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the completion of pull-ahead work resulting in unnecessary OT and contractor expense.

Objectives: The project will add value by: (1) improving Work Planning Annual Forecast Process: This involves the enhancement of automated inputs, processing, and reporting with a shift towards a more asset-driven prioritization method; (2) converting Monthly Work Plans into Weekly Schedules: Establish a process that seamlessly transforms monthly work plans into executable weekly schedules for easy handoff from planning to scheduling; (3) providing the ability to Run Forecasting and Planning Scenarios: Execute forecasting and planning scenarios and provide comparative analysis; (4) improve system visibility of Work Planned jobs increasing forecast accuracy of downstream processes; and (5) creating multiple dashboards based on the audience of the data providing visibility across all levels of Operations Leadership as well as Supply Chain proactively informing of upcoming workload, potential gaps, opportunities for contingencies if levers are pulled, and clean executable work keeping our workforce fully engaged and productive. This results in improved Field Operations and Customer Satisfaction with delivery commitments and meeting reliability and compliance dates.

Scope: The project scope includes the following: (1) developing a system for Work Planning Annual and Monthly forecast with automation; (2) creating the ability to translate the Monthly forecast into an executable Weekly Schedule; (3) creating technology for running Planning Scenarios with ability to compare scenarios for optimized field execution; (4) improving system visibility of Work Planned jobs increasing forecast accuracy of downstream processes (ie. materials); and (5) building Dashboards and reports to provide visibility and help management maintain process control.

Alternatives: Alternatives considered: (1) Purchase commercially available system. This option was not selected as a single all-encompassing system does not link the Annual forecasting to execution. Products reviewed included Prometheus. (2) Microsoft Excel based solution. Extending the Microsoft Excel based solution was not selected as it did not provide the level of data integration for controlling a large number of forecasted work items. (3) Development of a system that integrates with our SAP investment. This option was not selected as it does not align to expected value delivery timeline. (4) Purchase a SaaS solution to enable planning and forecasting with integration to our SAP work management system. The fourth alternative was selected because it aligns to the expected value delivery timeline and meets the functional requirements.

Q. Does this complete your direct testimony?

A. Yes. The Gas Operations Division is committed to meeting the needs of Consumers Energy's 1.8 million natural gas customers by consistently delivering services safely and efficiently. The Company's proactive approaches to Gas Operations, Maintenance and Metering, Field Operations, Operations Performance, and Operations Management, ensure that the Company adequately prepares for the future circumstances required to continue serving the needs of customers and the communities in which they live.

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	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

HEATHER M. PRENTICE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Heather M. Prentice, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Environmental Compliance, Risk Management & Governance in the Environmental Quality and Sustainability Department.

Q. How long have you been employed by Consumers Energy?

A. I have been employed by Consumers Energy since 2008.

Q. Please describe your educational background and work experience.

A. I graduated from Ohio Northern University in 1999 with a Bachelor of Science degree in Civil Engineering with an Environmental Option. I am a Registered Professional Engineer in the states of Michigan and Ohio. My environmental investigation and remediation work experience spans 25 years and includes a variety of technical and managerial responsibilities.

After graduating in 1999, I started working for Water Resources & Coastal Engineering, a consulting firm based in Solon, Ohio. As a project engineer, my responsibilities included modification of the facilities planning reports for the City of Cleveland's four major water treatment plants per review comments, analysis of pump performance for various service levels (pressure zones), and estimation of the construction costs for various projects recommended in the plan. I then worked at Camp, Dresser & McKee in its Cleveland, Ohio office. As project engineer, I managed tasks from multiple projects including odor sampling, soil removal, water treatment, and regional storm-water drainage study projects. Project tasks included developing contract drawings and specifications for the removal of soil stockpiles, interacting with regulatory agencies, preparing construction cost estimates for water treatment equipment, developing public education materials, and hydrologic and hydraulic modeling of interjurisdictional watersheds.

In October 2001, I accepted a position with NTH Consultants, Ltd. ("NTH") in Lansing, Michigan. Throughout my career at NTH, I assumed increasing levels of responsibility from staff engineer to assistant project engineer, and to project engineer on a variety of environmental and civil projects. Projects included due diligence assessments, subsurface explorations, underground storage tank ("UST") removal and closure, and risk-based contaminant exposure evaluations. More specifically, I managed and performed numerous Phase I Environmental Site Assessments ("ESAs") in accordance with American Society for Testing and Materials standards and United States Environmental Protection Agency All Appropriate Inquiry. Based on the Phase I ESA results, I planned and completed Phase II ESAs to characterize and delineate the horizontal and vertical extents of contamination. When appropriate, Baseline Environmental Assessments and due-care plans were prepared in accordance with Michigan Department of Environment, Great Lakes and Energy ("EGLE") guidelines. I have remediated and closed several USTs. I also have extensive construction management experience, including bid specification package development, trade contractor procurement and management, field oversight of construction and demolition projects, and associated documentation and report preparation.

After nine years in consulting, I accepted a position at Consumers Energy in August 2008. I was initially hired to serve as the project engineer and construction manager for the Little Traverse Bay Environmental Project. In this role, I managed the design and implementation of remedial strategies to address water impacted by cement kiln dust that was entering Little Traverse Bay. Some of the specific responsibilities included managing the project reserve, serving as the day-to-day interface with regulators, maintaining compliance with the final agreement with the State of Michigan, and interfacing with the impacted stakeholders. I also held the overall responsibility for project permitting, the adequacy of engineering design, selection of the contractor(s), project scopes, schedules, and budgets.

In January 2014, I became supervisor of the Risk Management group within the Environmental Compliance, Risk Management & Governance section of the Environmental and Laboratory Services Department. In this role, I became familiar with the status of the 23 Manufactured Gas Plant ("MGP") sites being managed by the Company. I served as the technical resource to the project managers and assisted with aligning the direction of the MGP Program. In January 2015, I became the Director of the Environmental Compliance, Risk Management & Governance section of the Environmental and Laboratory Services Department. The Environmental and Laboratory Services Department is now the Environmental Quality and Sustainability Department.

Q. What are your responsibilities as Director of Environmental Compliance, Risk Management & Governance?

A. As Director of Environmental Compliance, Risk Management & Governance, I am responsible for Environmental Compliance Assurance (corporate-wide environmental management system implementation), Environmental Risk Management (assessing and mitigating corporate environmental risks), and Environmental Governance to help ensure the Company maintains its strong record of excellent environmental stewardship. An integral part of the Environmental Risk Management function includes planning, directing, and controlling the investigation and remediation/risk management at former MGP sites and Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA" or "Superfund") sites where Consumers Energy is a responsible party. My section also supports the natural gas and electric operating organizations of Consumers Energy regarding the investigation and remediation of environmental contamination. The Risk Management section is also responsible for conducting environmental due diligence assessments for the acquisition, sale, lease, and licensing of Consumers Energy property.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I provided testimony in Case Nos. U-17882, U-18124, U-18424, U-20322, U-20650, U-21148, U-21308, and U-21490.

Q. Are you a member of any professional societies or organizations?

A. Yes. I represent Consumers Energy on the MGP Consortium. The MGP Consortium is discussed later in my testimony.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to: (i) identify the former MGP sites at which Consumers Energy has a present or former ownership interest; (ii) discuss environmental requirements for investigation and remediation by Consumers Energy at these sites; (iii) identify and describe expenditures for environmental response activities at these sites that the Company is seeking approval to recover in this Commission case; and (iv) address the prudency of these expenditures.

Q. How is your direct testimony organized?

A. I will discuss the environmental remediation at Consumers Energy's former MGP sites in Sections I through IV of my direct testimony. In Section I of my direct testimony, I will identify and provide information regarding the MGP sites Consumers Energy has identified where it has a present or former ownership interest. In Section II of my direct testimony, I will discuss reasons that Consumers Energy is undertaking environmental investigation and remediation activities at these sites. In Section III of my direct testimony, I will discuss costs and the prudency of the costs. In Section IV of my direct testimony, I will discuss investigation, remediation activities, and overall progress at MGP sites. The accounting and ratemaking treatment for the MGP-related costs which I identify will be discussed by Company witness Matthew J. Foster.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-90 (HMP-1)	Manufactured Gas Plant Sites Information; and
Exhibit A-91 (HMP-2)	MGP Environmental Response Cash Outflows – January 2024 to December 2024 by Phase & Site.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes. These exhibits were prepared by me or under my supervision.

Q. Please summarize your direct testimony.

A. Consumers Energy has identified 23 sites that formerly housed MGPs at which it has a present or former ownership interest. Reasonable and typical industry practices during the MGP era resulted in environmental contamination that is unacceptable under current environmental standards and laws. Consumers Energy has incurred, and will continue to incur, costs related to investigation and remediation of MGP sites. Costs related to investigation and remediation of MGP sites that Consumers Energy is seeking approval of in this case total approximately $997,000 that will be deferred (amortized) over 10 years, and approximately $963,000 in non-deferred (operation and maintenance ("O&M")) dollars in addition to the normal direct management expenses. The split in costs will be discussed further in Section III of my testimony. These costs are reasonable and prudent, as discussed later in my testimony.

SECTION I – Information on MGP Sites

Q. How many MGP sites has Consumers Energy identified where it has a present or former ownership interest?

A. Consumers Energy has identified 23 sites that formerly housed MGPs at which it has a present or former ownership interest. These sites are listed on Exhibit A-90 (HMP-1). Gas was manufactured from these locations for various periods during the late 1800's until the 1950's when the last MGP was retired. The 23 sites were acquired or built by Consumers Energy between 1917 and 1934 on behalf of customers. Predecessor companies were either acquired by Consumers Energy or no longer exist.

Q. Please describe Exhibit A-90 (HMP-1).

A. Exhibit A-90 (HMP-1) provides a summary of site information for each of the 23 former MGP sites, listing: (i) location; (ii) approximate size of the site in acres; (iii) estimated peak plant capacity; (iv) date the plant was acquired or built by Consumers Energy; (v) date natural gas arrived; (vi) date put on standby status; (vii) when the plant was retired; (viii) when the holder (the MGP storage tank) was retired; (ix) the current property owners; (x) the current property use; and (xi) the current site status.

Q. What was the role of MGPs?

A. MGPs were formerly an integral part of gas utility service. Prior to the availability of natural gas, gas was manufactured. By the end of the 19th century, manufactured gas was widely used for lighting, heating, and cooking. As natural gas became available, it replaced manufactured gas as a base fuel. Even after natural gas became available, maintaining the ability to manufacture gas on a stand-by basis was viewed as important. At most of Consumers Energy's sites, after natural gas replaced manufactured gas, the plants retained their ability to manufacture gas for use in the event of gas shortages. In addition, the MGP storage tanks, often referred to as holders, were used to store natural gas.

SECTION II – Need for Environmental Investigation and Remediation

Q. Why is Consumers Energy undertaking environmental investigation and remediation activities at former MGP sites?

A. The levels of environmental awareness have increased significantly since the time when MGPs were operated. During MGP operations, the manufacture of gas resulted in various by-products which are now recognized as being environmentally harmful. Consumers Energy has discovered soil and/or ground/surface water contamination at all 23 of the former MGP sites during remedial investigations. Under current environmental standards, Consumers Energy will incur cleanup costs at all of the sites.

The costs of environmental investigation and remediation with respect to former MGP sites are necessary and ongoing costs of doing business which were not, and could not have been, anticipated during the time MGPs were in operation. Awareness of the environmental risk associated with these by-products did not exist during the MGP era. The costs of investigation and remediation are prudent expenditures that are based on public policy considerations of protecting the environment and natural resources of the State to help ensure the quality of life that customers desire. These costs are unavoidable and do not arise out of any failure to meet standards at the time the plants were in operation.

Q. How will site remediation requirements be determined for the former MGP sites in Michigan?

A. The overall framework for environmental response activities is provided by several statutory enactments. In 1980, Congress enacted the CERCLA, commonly referred to as Superfund, which required potentially responsible parties to investigate and remediate various wastes. In 1982, the Michigan Environmental Response Act ("Act 307") was enacted. In 1990, the State of Michigan passed amendments to Act 307, which established a state program similar to the federal Superfund law, although broader in scope. In 1994, additional amendments were made, and Act 307 was recodified as Part 201 of Act 451 ("Part 201"), the Michigan Natural Resources and Environmental Protection Act, MCL 324.20101 *et seq*. Part 201 provides the primary framework for investigation and remediation of Consumers Energy's former MGP sites. EGLE oversees Michigan's Part 201 Program. As Director of Environmental Compliance, Risk Management & Governance, I am responsible for the Company's primary interface with EGLE on Part 201 issues.

Q. What EGLE division administers Michigan's Part 201 Program?

A. EGLE's Remediation and Redevelopment Division administers programs that facilitate the cleanup and redevelopment of sites of environmental contamination in Michigan. This includes the responsibility to oversee Michigan's Part 201 Program. Among other things, it oversees and provides information to support cleanup of contaminated sites by responsible parties, initiates enforcement action when voluntary compliance cannot be achieved, and recovers State cleanup funds from liable parties. Administrative Rules, Operational Memorandums, and Generic Cleanup Criteria are provided by EGLE. A responsible party is obligated to diligently pursue cleanup at contaminated sites to be compliant.

Q. Who are responsible parties under Part 201?

A. Under Part 201, those liable for response activity costs include: (i) the owner or operator of a facility, if the owner or operator is responsible for an activity causing a release or threat of release; and (ii) the owner or operator of a facility at the time of disposal of a hazardous substance, if the owner or operator is responsible for an activity causing a release or threat of release. Under certain circumstances, others can also be liable for response activity costs.

A party may be liable under Part 201 even though the act causing environmental contamination was lawful and reasonable at the time. Any potentially responsible party may be held liable for the entire cost of investigation and remediation of a site. Part 201 states that it applies regardless of whether the release or threat of release of a hazardous substance occurred before or after the effective date of Part 201.

Q. What is a utility's responsibility at a former MGP site that it owned or operated?

A. Part 201 requires that when a liable owner or operator of a facility obtains information that there may be a release of a hazardous substance at a facility for which they are liable, such owner or operator must take appropriate action, including confirming the existence of the release, determining the nature and extent of the release, reporting the release to EGLE if there was a reportable quantity released, and immediately taking steps to stop any continuing release. Part 201 contains affirmative obligations to avoid exacerbation of any existing contamination. The liable owner or operator must "diligently pursue" environmental response activities, including investigation and remediation, and ultimately address all contaminants associated with the site. Consumers Energy has been the owner or operator for all the former MGP sites listed on Exhibit A-90 (HMP-1) and currently owns all or portions of most of the former MGP sites listed.

EGLE has responsibility to oversee and coordinate all activities required under Part 201. EGLE is authorized by Part 201 to request or order remediation by one or more responsible parties or to undertake response activities and to recover costs incurred from responsible parties later. Each year, EGLE publishes a list of Michigan Sites of Environmental Contamination ("Part 201 Inventory of Facilities"). There are currently about 17,916 sites of environmental contamination listed on the Part 201 Inventory of Facilities. All 23 Consumers Energy former MGP sites are on the Part 201 Inventory of Facilities.

Q. Has Consumers Energy identified any former MGP owners or any predecessor or successor companies of such owners for the 23 sites at which Consumers Energy has a present or former ownership interest?

A. No. A prior search for former MGP owners or any predecessors or successor companies of such owners for the 23 sites did not find any in existence today. Hence, no other potentially responsible parties have been identified.

Q. Does a site have to be listed on the Part 201 list in order for an owner or operator to be obligated to undertake environmental response activities or to incur response costs?

A. No. EGLE is authorized to require that environmental response activities be undertaken by a responsible party even if the site is not listed on the Part 201 list. In addition, discovery of contamination related to MGPs at or near a former MGP site can require an owner or operator to undertake response activities.

Q. What is Consumers Energy's strategy for the management of the former MGP sites?

A. Consumers Energy's strategy is to minimize the impact from the former MGP sites on human health and safety, as well as to minimize any damage to the surrounding natural resources, in the most cost-effective way possible. The strategy for the management of the former MGP sites is based on the environmental risk that these sites pose to human health, safety, and damage to natural resources. Consumers Energy routinely assesses the environmental exposure and/or exacerbation risks at each site based on changing conditions and new information. Based on the risk assessment, response activities are prioritized, developed, designed, and implemented.

The environmental response strategy will be determined based upon the land uses and zoning at individual facilities, the environmental media involved, and the relevant exposure pathways. The key elements of an exposure pathway are a source or release of a hazardous substance, an exposure point, an exposure route, and a transport mechanism. In developing an environmental response strategy at a particular site, the Company develops a plan to address contamination in all environmental media, including but not limited to: (i) contaminated groundwater; (ii) contaminated soils; (iii) contaminated sediments; and

(iv) vapor intrusion. Based on the media impacted and the nature of contaminant(s), remediation strategies may vary including removal, recovery, containment/barrier technologies, monitored natural attenuation, etc. Once exposure risks for all contaminants in all applicable media for all exposure scenarios are mitigated, the site may be eligible for No Further Action ("NFA").

Q. Is it possible under current regulations to obtain total closure status for an environmentally contaminated former MGP site?

A. No. Part 201 of the Natural Resources and Environmental Protection Act, 1994 Public Act 451, was revised in 2010 by adding a regulatory mechanism that allowed for NFA at a contaminated site if certain conditions are met. However, NFA does not mean there is a total closure. Rather, NFA is a regulatory status that allows the site to maintain a "negotiated status quo," that requires no or minimal ongoing remedial actions. It is the responsibility of the owner/operator to maintain the agreed upon conditions of the NFA agreement such as due care, groundwater monitoring, and O&M of control technologies. If any of the conditions are not maintained, or there is a change in conditions, the NFA status becomes invalid. While NFAs acknowledge remedial actions performed and what exposures/risks are still present at the sites, approvals of these actions do not eliminate present or future liabilities or close the site.

Q. Who is financially responsible if the negotiated status is not maintained and work needs to be performed?

A. Typically, the party that commits the noncompliance will ultimately be financially responsible.

Q. Is Consumers Energy looking into the possibility of obtaining NFA status at former MGP sites?

A. Yes. Consumers Energy is actively pursuing NFA at several former MGP sites. It should be noted that the Company does not consider a site eligible to pursue NFA status unless contamination in all environmental media is addressed. Consumers Energy submitted and obtained NFA status for the following former MGP sites:

- Ionia – 2013
- Grand Ledge (site proper) – 2016
- Marshall – 2019
- Mt. Clemens (site proper) – 2021
- Royal Oak – 2021
- Alpena – 2021
- Bay City (site proper) - 2022
- St. Johns (site proper) – 2023
- Manistee (Operational Site) – 2023
- Hastings (site proper) – 2024
- Bay City (off-site) – 2024

An NFA was submitted for the Sault Saint Marie MGP site but was ultimately withdrawn due to lack of property owner signature on the necessary restrictive covenant. A Certificate of Completion was obtained for this site in 2021.

Consumers Energy has also initiated discussions with EGLE regarding several MGP sites that potentially may qualify for NFA status. This is discussed later in my testimony. Due to the complexity of the remediation that needs to be addressed and current status of remediation, it would not be efficient at present to seek NFA status at all of the sites. In some cases, it may be more practical to obtain a Certificate of Completion (described below) due to site restrictions/liability concerns.

Q. Does NFA mean that there will be no additional costs on these sites?

A. No. There will be costs associated with these projects even after they achieve NFA status. These costs may include routine sampling, preparing and submitting reports, some O&M tasks, due care, etc. These long-term, post-NFA costs may be significant.

Q. What is a Certificate of Completion?

A. A Certificate of Completion is a written response provided by EGLE that a response activity has been completed in accordance with the applicable requirements of Part 201 and is approved by EGLE.

Q. What are the benefits of a Certificate of Completion?

A. A Certificate of Completion provides EGLE concurrence that response activities were performed at a site as proposed. However, there are no requirements for either Post Closure Agreements or financial assurance with a Certificate of Completion.

Q. Has the Company received any Certificates of Completion?

A. Yes. The Company received a Certificate of Completion from EGLE in July 2019 for the Sediment Response Action project at the Flint East MGP, and for the Sault Saint Marie site as discussed earlier. The Certificate of Completion for the Manistee River Sediment work was deemed administratively approved in 2022.

Q. What is a Post Closure Agreement?

A. It is an agreement that may be required by EGLE based on activities needed following NFA approval. The agreement is between EGLE and the submitting entity. It contains terms regarding future liabilities and potential reopeners of the NFA document.

<u>SECTION III – Costs and Prudence</u>

Q. What levels of expenditures are attributable to environmental response activities at the 23 former MGP sites?

A. The level of environmental response expenditures for the period January 2024 through December 2024 totals approximately $997,000 in deferred (amortized) dollars, and $963,000 in non-deferred dollars for the period of October 1, 2025 through September 30, 2026.

Q. Do these amounts include Consumers Energy's Project Management ("PM") costs?

A. No. As recommended by the Commission Staff ("Staff") in Case No. U-14547, the Company has excluded PM and associated costs from the MGP Environmental Response Cash Outflows.

Q. Please describe what types of costs were excluded from the MGP Environmental Response Cash Outflows.

A. The types of costs excluded are costs of Consumers Energy employees and associated expenses such as Labor, Lab Services, Fleet, Real Estate, business expenses, and computer charges. Those costs are included as O&M expense. In addition, Consumers Energy has excluded professional organization membership costs and lawn maintenance costs from the MGP Environmental Response Cash Outflows shown on Exhibit A-91 (HMP-2).

Membership fee expenditures and lawn care expenditures are included instead as O&M expenditures.

Q. Do the MGP Environmental Response Cash Outflows you are presenting in this rate case include professional membership fees?

A. No. As mentioned earlier, professional membership fees, specific to MGP remediation operation, are not included in the MGP Environmental Response Cash Outflows shown on Exhibit A-91 (HMP-2). However, professional membership costs are included in the MGP PM and Associated Costs included in the O&M portion of the rate case. The two specific professional memberships are the Utility Solid Waste Advisory Group ("USWAG") and MGP Consortium.

Membership in the USWAG is directly related to helping Consumers Energy evaluate environmental investigation and remediation response activities and to identify the most cost-effective MGP investigation and remediation measures that are protective of human health and the environment. The USWAG provides a technical resource for management of waste streams from the remediation of MGP sites allowing for protection of natural resources while minimizing unnecessary costs.

The MGP Consortium includes members from various utility companies in the nation who are currently managing MGP sites as part of their liability management. The MGP Consortium is designed to discuss and share knowledge or project experience between owners/operators of former MGP sites. Membership in the MGP Consortium has facilitated discussions about general MGP PM, remediation technology evaluation, remediation technology application, lessons learned, public relations, public policy trends, and vendor evaluations. These memberships have helped Consumers Energy in its evaluation of technical, regulatory, legislative, and policy issues related to the investigation and remediation of former MGP sites.

Q. Why have dollars been separated as non-deferred?

A. In Case No. U-20650, the Company agreed in rebuttal testimony to include routine monitoring and reporting and regulatory/legal requirements of Post Closure Agreements or other mechanisms after receipt of NFA, Remedial Action Plan, or Certificate of Completion approval as non-deferred (O&M) expenditures. This change began with the test year for Case No. U-21308. These costs are in addition to the direct management or other O&M costs previously discussed.

Q. What is the amount of the non-deferred MGP expenditures?

A. The additional amount of non-deferred MGP expenditures is $963,000. These expenses are covered in Company witness Matthew J. Foster's Exhibit A-47 (MJF-5).

Q. Were MGP environmental response activity costs incurred prior to January 2024?

A. Yes. Costs for environmental response activities for periods prior to January 2024 were reviewed and audited by Staff in Case No. U-21490 and earlier cases; therefore, these costs have not been included on Exhibit A-91 (HMP-2) in the current case.

Q. At how many of the sites will Consumers Energy incur deferred (amortized) costs during the period January 2024 through December 2024?

A. Costs will be incurred at 12 sites.

Q. Why were deferred costs not incurred at all of the 23 MGP sites?

A. As the sites reach NFA status or point of minimal activity, the Company does not necessarily use consultants for the remaining activities. The Company will use internal staff to complete the necessary obligations and reporting to reduce the program costs.

Q. Please explain Exhibit A-91 (HMP-2).

A. Exhibit A-91 (HMP-2) shows the cash outflows for environmental investigation and remediation during the period January 2024 through December 2024 for each MGP site. Costs are shown by phase and in total for all 23 MGP sites.

Q. How were these costs developed?

A. Costs shown on Exhibit A-91 (HMP-2) include projected costs. Costs for January through December 2024 are projected costs based on the work scope developed for the sites and the long-term strategy.

Q. How did you determine the costs for activities that have not yet occurred?

A. The cost for each activity is based upon the strategy identified to move the site toward NFA/Certificate(s) of Completion. The strategies have been developed based on past experience at Consumers Energy sites and other sites, overall knowledge, site background, site use, site investigations, remedial investigations, and feasibility study evaluations. Based on all this information and data, we determine, with assistance from the consultants involved with each of these sites, how to move sites forward in the most prudent way possible while maintaining compliance with EGLE regulations and requirements.

Q. Why are the costs incurred different at different sites?

A. Environmental response costs are influenced by a number of site-specific factors. Costs can vary significantly depending on: (i) the nature and extent of contamination; (ii) size of the site; (iii) geology of the site; (iv) presence of surface water and depth of groundwater; (v) present and future use of the site; and (vi) types of remedial action. The costs on the exhibit differ due to site-specific factors.

Q. What MGP environmental expenditures are you seeking approval for in this case?

A. Consumers Energy is seeking approval in the current case for deferred (amortized) MGP environmental response expenditures from January 2024 through December 2024. The Company is also seeking approval of non-deferred (O&M) recovery of MGP expenditures for the test year that covers November 1, 2025 through October 31, 2026.

Q. Are the expenditures that Consumers Energy is seeking recovery for in this case reasonable and prudent?

A. Yes. The need for environmental investigation, remediation, and the parameters for cleanup are mandated and defined by the state and federal government. The costs of investigation and remediation are not based on any imprudence, but upon public policy considerations of protecting the environment and natural resources of the State on behalf of the customers the Company serves. MGP site investigation and remediation costs are legitimate and necessary costs of doing business. The costs incurred were costs for activities that are necessary under current environmental regulations and overseen by EGLE. The need for incurring such costs is based upon current environmental awareness, not any fault on the part of the operator of the former MGP facilities.

Q. Does the Company coordinate site activities with EGLE?

A. Consumers Energy has taken a proactive role with EGLE. By taking a proactive role, Consumers Energy has had a better opportunity to participate in decisions involving investigation and remedial actions than if EGLE were to order remediation or to undertake remediation itself. Consumers Energy has undertaken response activities in an efficient manner to minimize costs consistent with health and safety considerations. Consumers Energy has sought approval from EGLE of the most cost-effective remediation, which is protective of human health and the environment, as allowed by law. The expenditures which Consumers Energy is seeking to recover in this case are reasonable and prudent.

Q. Does the Company use competitive bidding as a means of controlling costs?

A. Yes. Current Company policies require competitive bidding for purchases of materials and/or services initially over $100,000, except for emergencies or where only one vendor can supply the goods or services. For smaller scale response activities, such as drilling and small disposal activities, the site consultant handles the initial bidding and ensures the contracted costs are reasonable. For larger activities, the Company competitively bids the project. If competitive bids are not sought, the Company documents reasons why the competitive bidding process was not used. During the competitive bidding process, the qualifications of each contractor and subcontractor are reviewed to determine if they have the resources and expertise to complete the tasks on which they are bidding. The Company also evaluates contracting strategies (e.g. time and materials, lump sum, not to exceed, etc.) to determine which will provide the most value and reduce risks during the projects.

Q. Please describe how the consultants used were selected.

A. The initial consultants for each site were selected using a bidding process. Consultants who were interested bid for each MGP site separately. As part of the competitive bidding process, the qualifications of each consultant were reviewed to determine if they had the resources and expertise to complete the projects on which they were bidding. The Company currently has five consultants for the MGP sites. Using the same consultant for more than one site increases efficiency and improves consistency. Limiting the consultants to fewer than all sites helps assure that they will be able to complete the work in a timely fashion.

Q. Please discuss Environmental Response Cash Outflows at the MGP sites.

A. The majority of the Environmental Response Cash Outflows shown on Exhibit A-91 (HMP-2) are for remedial actions. Remedial action costs were incurred at 6 of the 23 sites. The remedial action costs incurred include collection of data supporting remedial action and response activities such as: (i) source-area impacted soil removal; (ii) operation of existing in-site remediation systems; (iii) groundwater monitoring; (iv) treatability studies; and (v) other activities intended to resolve containment issues. The environmental response costs also include activities related to Remedial Investigations, Feasibility Studies, and NFA. The NFA phase tasks included EGLE negotiations, preparation of NFA reports, property surveys, and recording use restrictions, etc. O&M tasks included monitoring, operation, maintenance, due care, and reporting obligations. Response activities are discussed in more detail later in my testimony.

<u>SECTION IV – Response Actions</u>

Q. What types of environmental response activities may be required at a former MGP site?

A. The sequence, timing, and magnitude of response activities vary from site to site depending upon the size of the site, the degree of environmental contamination, current and potential future land use, the degree of enforcement discretion exercised by EGLE, the media impacted, and other site-specific factors. However, the usual sequence of environmental response activities which would typically be undertaken at a former MGP site would be:

1. Site Investigation;
2. Remedial Investigation;
3. Interim Response Activities;
4. Feasibility Study;
5. Remedial Action;
6. NFA; and

7. O&M.

Q. Please briefly describe each of these activities.

A. **<u>Site Investigation</u>:** A Site Investigation involves research of site-related information such as available historical records, past and current site uses, topographical maps, engineering drawings, and a review of potential sources of environmental contamination. A site visit is also usually done during a Site Investigation to relate the information collected by the records search to current site conditions and to conduct a visual inspection for any obvious signs of MGP contamination.

<u>Remedial Investigation</u>: The purpose of a Remedial Investigation is to define the nature and extent of contamination at a site. Consumers Energy worked with EGLE to reach a common understanding on facility prioritization criteria as it relates to risk assessment and exposure pathways. In addition, Consumers Energy sought input, review, and concurrence from EGLE on major remedial investigation work plans. This collaborative approach allowed Consumers Energy to be better responsive to EGLE concerns and issues in developing and implementing work plans.

The Remedial Investigation includes the collection and analysis of samples of surface soils, subsurface soils, groundwater, and/or surface water. Limited field screening measurements of soil, gas, and air samples may also be conducted. These samples are analyzed for chemicals of concern that are typical of MGP by-products and wastes. Remedial Investigations typically generate solid and liquid waste, called Investigation Derived Waste, that must be disposed per state and federal regulations.

<u>Interim Response Activities</u>: Interim Response Activities may be required if the results of the Remedial Investigation or other information indicates a need to abate a threat to human health or to the environment on an interim basis while further investigation occurs. Examples of the types of Interim Response Activities which may occur for contaminated soils include erecting a fence, installing drainage controls and stabilization, capping, removal, and treatment or disposal of the grossly contaminated soils to eliminate direct-contact hazards and to prevent further migration. Free phase product recovery is also considered as an Interim Response Activity. Interim Response Activities can also generate solid and liquid waste that must be disposed per state and federal regulations.

Feasibility Study: The purpose of the Feasibility Study is to develop, evaluate, and select which of several remedial action alternatives, including no action, may be appropriate. The Feasibility Study involves identifying appropriate remedial technologies, determining the applicability of the technologies to a specific site, evaluating the implementability and total cost of operations, and developing a cost benefit analysis.

Remedial Action: Remedial Action includes, but is not limited to, cleanup, removal, containment, isolation, destruction, or treatment of a hazardous substance released or threatened to be released. Some remedial actions may require operation of active remediation systems, which require significant ongoing activities along with performance monitoring. Remedial actions may generate significant solid and liquid waste that must be disposed per state and federal regulations.

NFA: Once Remedial Action is complete, and the applicable cleanup criteria are achieved, then the project may be eligible to seek NFA status. The NFA is usually associated with some land and resource use restrictions along with long-term monitoring and/or due-care obligations. As discussed earlier in my testimony, it is not possible under current regulations to obtain total closure status for the former MGP sites. The NFA activities may include NFA report preparation, negotiations with EGLE and other stakeholders, developing and recording site surveys, restrictive covenants, etc. Preparation of Certificate(s) of Completion will also be included as NFA activities.

<u>O&M</u>: Activities performed as O&M may include routine monitoring data collection, due-care activities, system operation and maintenance, and associated reporting. The O&M activities may be required indefinitely.

Q. What are some examples of environmental response activities that have either been completed during the January 2024 through October 2024 timeframe or are currently underway?

A. Examples of projects that have been completed or are underway include the following:

- Bay City MGP site – Submitted a NFA to EGLE for MGP area south of 9th Street.

- Charlotte MGP site – NFA drafting was initiated.

- Flint Court MGP site – Annual groundwater sampling was performed. Continued quarterly vapor intrusion sampling of the former by-products building.

- Flint East MGP site – Annual groundwater sampling was performed. Conducted inspections and bathymetry evaluations within sediment cap reach. Completed the vapor intrusion assessment near the Rec Center building with no issues identified. Continued to provide review comments on the dam removal design as it impacts the river sediment removal work that was performed in 2017. Performed cap inspections during work on dam.

- Kalamazoo MGP site – Collected one additional round of groundwater samples from new monitoring wells as well as certain key monitoring wells to have current data in advance of preparing the NFA document. Collected an additional round of sub-slab and indoor air samples to evaluate the vapor intrusion pathway. Prepared the NFA document and associated institutional control documents (restrictive covenants and public highway institutional control).

- Jackson MGP site – Began preparing a Comprehensive Project Summary Report.

- Manistee MGP site (ongoing) –Performed quarterly groundwater sampling at the former relief holder site. Expanded the air sparge system on the former relief holder site. Performed a cyanide evaluation based on observations during groundwater sampling events.

- Owosso – Annual groundwater sampling was performed. Purchased three residential homes impacted by the former MGP. Performed engineering for demolition of the residential homes. Demolition of the homes occurred in October 2024.

- Plymouth MGP site – Annual sampling was performed at the site. Performed delineation work in front of Messina garage to evaluate potential source controls. Also, replaced monitoring wells as requested by EGLE.

Additionally, investigations, routine monitoring, reporting, NFA activities, and O&M activities were also conducted.

Q. Does the Company need a formal approval by EGLE to implement response activities?

A. No. A formal approval is not required to implement response activities. However, Consumers Energy has taken a proactive role with EGLE to provide an opportunity to collaborate with EGLE regarding decisions involving investigation and remedial actions. This approach helps minimize the possibility of EGLE issuing a remediation order or undertaking the remediation itself at Consumers Energy's expense. We believe that our continuous involvement with EGLE and the collaborative approach results in cost-effective remediation that is protective of human health and the environment as required by law. This collaborative approach is carried out both through formal and informal means.

Q. Can you summarize any recent approvals that Consumers Energy has received from EGLE?

A. Based on the activities completed from January 1 through October 31, 2024, the Hastings and Bay City (off-site) NFAs were approved by EGLE.

Q. How does the Company respond to EGLE requests for inclusion of additional parameters in testing or any other requests at a site?

A. The Company has highly trained remediation experts that will review the request, evaluate the value provided by the request, and discuss this evaluation with EGLE. Inclusion of additional parameters or other requests suggested by EGLE can significantly increase costs. In addition, practical and technical limitations must be considered. If these are not typical for the type of remedial action underway, the Company will attempt to determine if there is an alternative or more cost-effective way to address EGLE's concerns.

As mentioned earlier in my testimony, Consumers Energy has taken a proactive role with EGLE to provide an opportunity to collaborate with EGLE regarding decisions involving investigation and remedial actions. This approach helps minimize the possibility of EGLE issuing a remediation order or undertaking the remediation itself at the Company's expense. Consumers Energy seeks approval from EGLE of the most cost-effective remediation that is protective of human health and the environment as required by law.

Q. Please describe soil and/or groundwater remediation systems in operation.

A. Currently, there is one active groundwater remediation system at the MGP sites. The Cross Street site remediation system consists of a groundwater air sparge system, installed in 2011. This system was deactivated in 2019 to evaluate groundwater conditions and allow for in-situ soil stabilization of the impacted soils near the former holder location. The system remained off until the spring of 2022 when groundwater concentrations began to rebound. The system was expanded in 2024 to address the concentrations in wells outside of the original capture area of the system. It is currently anticipated that the system will need to operate for two years to address the concentrations present at the site.

Q. Does the Company have any inactive soil and/or groundwater remediation systems?

A. Yes. The multiphase system that consists of a Light Non-Aqueous Phase Liquid recovery system, a groundwater pump and treatment system, and a Soil Vapor Extraction and treatment system at the Jackson MGP site has been inactive since April 2016. The system is slated for decommissioning in 2025.

Q. Were there any MGP property ownership changes in the time period covered by this filing?

A. No.

Q. Are the MGP costs described in your testimony reasonable and prudent?

A. Yes, they are. They are reasonable and prudent costs of doing business.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

DIRECT TESTIMONY

OF

HEATHER L. RAYL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Heather L. Rayl, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rates Analyst in the Revenue Requirements Section of the Rates and Regulation Department.

Q. Please state your educational background.

A. I received both a Bachelor of Arts and a Master of Business Administration degree from Michigan State University in 1993. I am also a Certified Public Accountant registered in the state of Michigan.

Q. Please describe your business experience.

A. After receiving my degrees in 1993, I have held various positions in audit, accounting, and finance with a focus in financial statement preparation and analysis, general ledger analysis, and preparation and analysis of statutory annual reports.

In 2004, I started my career at Consumers Energy as a Senior Analyst in the Accounting Research and External Financial Reporting Department. My responsibilities included the research and documentation of numerous technical accounting topics for departmental clients, including United States Generally Accepted Accounting Principles issues, United States Securities and Exchange Commission issues, utility/regulatory accounting issues. I was also responsible for the preparation and documentation of financial statement disclosures in the Company's Forms 10-K and 10-Q, with a focus in regulatory matters.

In 2013, I transferred to Consumers Energy's Rates and Regulation Department. During my tenure, I have held positions in Revenue Requirements and Rate Design as a Senior Rates Analyst.

Q. What are your job responsibilities?

A. I am responsible for conducting analyses related to the Company's revenue requirements and developing testimony and exhibits in support of proposals in regulatory proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you previously testified in any proceedings before the Commission?

A. Yes. I have filed testimony in Gas Rate Case Nos. U-18124, U-18424, U-21148, U-21308, and U-21490; Gas Cost Recovery ("GCR") Plan Case Nos. U-17334, U-17693, U-17943, U-18151, U-21269, and U-21437; GCR Reconciliation Case Nos. U-16924-R, U-17133-R, U-17334-R, and U-17693-R; Gas Revenue Decoupling Case No. U-18367; Renewable Energy Plan Case No. U-18231; and Investment Recovery Mechanism Reconciliation Case No. U-20893.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to: (i) identify and support the Part I exhibits required by the Commission's Order in Case No. U-18238 ("Filing Requirements") and (ii) present Consumers Energy's revenue requirement calculation for the projected test year.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into four sections:

Section I: Historical Year

Section II: Projected Test Year

Section III: Rate Impact from the Sale of the Riverside Storage Field

Section IV: Accounting Treatment for MAOP Retesting Costs to Comply with New Federal Safety Standards

Q. Please describe the revenue requirements determination.

A. In compliance with the Filing Requirements, my direct testimony presents the revenue requirement for the historical year, explains the development of the revenue requirement for the projected test year, and reconciles the historical and projected test years. The Company demonstrates in this instant case that it requires a rate increase to its gas tariffs to earn a just and reasonable return.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the historical year exhibits identified in Section I of my direct testimony and the projected test year exhibits identified in Section II of my direct testimony.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

I. <u>HISTORICAL YEAR</u>

Q. What is the historical year used in your exhibits and supporting direct testimony?

A. Calendar year 2023 is the historical year in the instant case.

Q. Please identify the exhibits that you are sponsoring to comply with the Commission's Filing Requirements for the historical year.

A. I am sponsoring the following exhibits to satisfy the Commission's historical year Filing Requirements:

Exhibit A-1 (HLR-1)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2023;
Exhibit A-1 (HLR-2)	Schedule A-2	Financial Metrics - Gas Results Only;

Exhibit A-2 (HLR-3)	Schedule B-1	Rate Base for the Historical Year Ended December 31, 2023;
Exhibit A-2 (HLR-4)	Schedule B-2	Total Utility Plant for the Historical Year Ended December 31, 2023;
Exhibit A-2 (HLR-5)	Schedule B-3	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2023;
Exhibit A-2 (HLR-6)	Schedule B-4	Working Capital for the Historical Year Ended December 31, 2023;
Exhibit A-2 (HLR-7)	Schedule B-5	13-Month Average Balance Sheet for the Historical Year Ended December 31, 2023;
Exhibit A-2 (HLR-8)	Schedule B-6	Point-in-Time Balance Sheet for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-9)	Schedule C-1	Adjusted Net Operating Income for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-10)	Schedule C-2	Revenue Conversion Factor for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-11)	Schedule C-3	Operating Revenue for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-12)	Schedule C-4	Cost of Gas Sold for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-13)	Schedule C-5	Operation and Maintenance Expenses for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-14)	Schedule C-5.1	Operation and Maintenance Expenses by Witness for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-15)	Schedule C-6	Depreciation and Amortization Expenses for the Historical Year Ended December 31, 2023;

Exhibit A-3 (HLR-16)	Schedule C-7	General Taxes for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-17)	Schedule C-8	Federal Income Taxes for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-18)	Schedule C-9	State Income Taxes for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-19)	Schedule C-10	Other (or Local) Taxes for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-20)	Schedule C-11	Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-21)	Schedule C-12	Income Tax Effect of Interest for the Historical Year Ended December 31, 2023;
Exhibit A-3 (HLR-22)	Schedule C-13	Interest Synchronization Adjustment for the Historical Year Ended December 31, 2023;
Exhibit A-4 (HLR-23)	Schedule D-1	Capital Structure and Rate of Return Summary for the Historical Year Ended December 31, 2023;
Exhibit A-4 (HLR-24)	Schedule D-2	Cost of Long-Term Debt (Excluding Securitization) for the Historical Year Ended December 31, 2023;
Exhibit A-4 (HLR-25)	Schedule D-3	Cost of Short-Term Debt for the Historical Year Ended December 31, 2023;
Exhibit A-4 (HLR-26)	Schedule D-4	Cost of Preferred Stock for the Historical Year Ended December 31, 2023; and
Exhibit A-4 (HLR-27)	Schedule D-5	Cost of Common Shareholder’s Equity for the Historical Year Ended December 31, 2023.

Q. How are these exhibits organized?

A. The exhibits are organized into schedules that present the development of the revenue sufficiency (Schedule A), rate base (Schedule B), adjusted net operating income ("NOI") (Schedule C), and rate of return (Schedule D).

Q. Who is sponsoring the historical year Schedule E exhibits?

A. Company witness Mustafa Ahmed sponsors the historical year Schedule E exhibits.

Q. Please describe the Schedule A exhibits for the historical year.

A. Exhibit A-1 (HLR-1), Schedule A-1, presents the computation of the revenue sufficiency for the historical year. Exhibit A-1 (HLR-1), Schedule A-1 is developed from the financial data presented in Schedules B, C, and D described below.

Exhibit A-1 (HLR-2), Schedule A-2, is a multiple page exhibit that provides financial metrics on a financial basis (pages 1 through 3) and on a ratemaking basis (pages 4 through 6) for the years 2019 through 2023. The calculation of the return on equity for each of these years can be found on pages 1 and 4.

Q. Please describe the Schedule B exhibits for the historical year.

A. Exhibit A-2 (HLR-3), Schedule B-1, presents the calculation of the average rate base for the historical year. The total rate base on line 8 of Exhibit A-2 (HLR-3), Schedule B-1, is carried forward to Exhibit A-1 (HLR-1), Schedule A-1, line 1. Exhibit A-2 (HLR-4), Schedule B-2, through Exhibit A-2 (HLR-8), Schedule B-6, support the development of the various components of historical rate base including net utility plant and working capital.

Q. Please describe the Schedule C exhibits for the historical year.

A. Exhibit A-3 (HLR-9), Schedule C-1, presents the calculation of adjusted NOI for the historical year. The adjusted NOI disclosed on line 36 of Exhibit A-3 (HLR-9), Schedule C-1, is carried forward to Exhibit A-1 (HLR-1), Schedule A-1, line 2. Exhibit A-3 (HLR-10), Schedule C-2, through Exhibit A-3 (HLR-22), Schedule C-13, support the development of the various components of adjusted NOI for the historical year. Schedule C data for the historical year is generally sourced to the Company's 2023 Form P-522 Annual Report. In addition, Exhibit A-3 (HLR-14), Schedule C-5.1, reconciles the historical year operating and maintenance ("O&M") expense by account, by witness, with the O&M expense amounts filed in the Company's 2023 Form P-522 Annual Report.

Q. Please describe the Schedule D exhibits for the historical year.

A. Exhibit A-4 (HLR-23), Schedule D-1, presents the overall rate of return summary for the historical year. The total weighted cost of capital is shown on line 14, column (h), and is carried forward to Exhibit A-1 (HLR-1), Schedule A-1, line 4. Exhibit A-4 (HLR-24), Schedule D-2, through Exhibit A-4 (HLR-27), Schedule D-5, support the development of various components of the overall rate of return for the historical year, including debt, preferred stock, common equity, and other sources of financing.

Q. Based on your review of the historical year exhibits, was there a revenue deficiency in the historical year?

A. No. I have calculated a revenue sufficiency of $9.4 million for the historical year.

Q. Please summarize the key findings from the historical year exhibits.

A. As presented on Exhibit A-1 (HLR-1), Schedule A-1, the key findings from the exhibits for the historical year ended December 31, 2023 are as follows:

		($ In Thousands)
Rate Base	$	9,479,241
Adjusted NOI	$	561,724
Overall Rate of Return		5.93%
Required Rate of Return		5.85%
Income Required	$	554,667
Income Sufficiency	$	(7,057)
Revenue Conversion Factor		1.3381
Revenue Sufficiency	**$**	**(9,443)**

Q. Do the above results include typical ratemaking adjustments such as weather, unusual, one-time, or out-of-period items, and regulatory disallowances?

A. Yes. The historical year presentation begins with the Company's booked results and ratemaking adjustments and normalizations are recognized, where appropriate, as summarized on Exhibit A-3 (HLR-9), Schedule C-1. I will discuss the ratemaking adjustments and normalizations in Section II of my direct testimony, which covers the projected test year.

II. PROJECTED TEST YEAR

Q. What is the projected test year used in your exhibits and supporting testimony?

A. The projected test year is the 12-month period ending October 31, 2026.

Q. Please identify the exhibits that you are sponsoring to comply with the Commission's Filing Requirements for the projected test year.

A. The following exhibits are being submitted to support and satisfy the projected test year Filing Requirements:

Exhibit A-11 (HLR-28)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-11 (HLR-29)	Schedule A-2	Financial Metrics – Ratemaking Basis – For the Projected 12-Month Period Ending October 31, 2026, Gas Results Only;
Exhibit A-11 (HLR-30)	Schedule A-3	Comparison of the Historical and Projected Revenue Requirement for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-12 (HLR-31)	Schedule B-1	Rate Base for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-12 (HLR-32)	Schedule B-2	Total Utility Plant for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-12 (HLR-33)	Schedule B-3	Depreciation Reserve and Other Deductions for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-12 (HLR-34)	Schedule B-4	Working Capital for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-12 (HLR-35)	Schedule B-5	Capital Expenditures Summary for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-36)	Schedule C-1	Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026;

Exhibit A-13 (HLR-37)	Schedule C-1.1	Development of Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-38)	Schedule C-2	Calculation of the Revenue Conversion Factor for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-39)	Schedule C-3	Operating Revenues for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-40)	Schedule C-4	Cost of Gas Sold for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-41)	Schedule C-5	Operation and Maintenance Expenses for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-42)	Schedule C-5.1	Summary of Inflation and Merit Increases Included in Operation and Maintenance Expenses for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-43)	Schedule C-6	Depreciation and Amortization Expenses for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-44)	Schedule C-7	General Taxes for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-45)	Schedule C-8	Federal Income Taxes for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-46)	Schedule C-9	State Income Taxes for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-47)	Schedule C-10	Other (or Local) Taxes for the Projected 12-Month Period Ending October 31, 2026;

Exhibit A-13 (HLR-48)	Schedule C-11	Allowance for Funds Used During Construction for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-49)	Schedule C-12	Income Tax Effect of Interest for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-13 (HLR-50)	Schedule C-13	Interest Synchronization Adjustment for the Projected 12-Month Period Ending October 31, 2026; and
Exhibit A-92 (HLR-51)		Pension and OPEB Volatility Mechanism - Amortization Expense for the Projected 12-Month Period Ending October 31, 2026.

Q. Please discuss the organization and format of the projected test year exhibits.

A. The projected test year exhibits are organized and formatted in a similar fashion to the historical year exhibits. The exhibits are organized into schedules that present the development of the revenue deficiency (Schedule A), rate base (Schedule B), and adjusted NOI (Schedule C). Company witness Marc R. Bleckman is sponsoring schedules that address rate of return (Schedule D). Company witness Ahmed is sponsoring sales, load, and customer data (Schedules E) exhibits. Company witnesses Samuel M. Geller, S. Austin Smith, and Kirkland D. Harrington are sponsoring cost-of-service allocation, present and proposed revenue, and proposed tariff sheets (Schedule F) exhibits, respectively.

Q. Please summarize the key findings for the projected test year exhibits.

A. As presented on Exhibit A-11 (HLR-28), Schedule A-1, the key findings from the exhibits for the projected 12-month period ending October 31, 2026 are as follows:

	($ In Thousands)
Rate Base	$ 11,750,740
Adjusted NOI	$ 545,492
Overall Rate of Return	4.64%
Required Rate of Return	6.22%
Income Required	$ 730,838
Income Deficiency	$ 185,346
Revenue Conversion Factor	1.3381
Revenue Deficiency	**$ 248,008**

Q. What inflation factors is the Company using in its presentation?

A. The Company utilized the inflation factors published by S&P Global, a leader in the market of financial information and analytics. The inflation factors in the June 2024 edition of S&P Global's *U.S. Economic Outlook* publication were 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026.[1] Exhibit A-13 (HLR-42), Schedule C-5.1, provides a summary of the inflation impacts included in this instant case.

Q. How has the Company addressed the filing requirement to reconcile the projected test year to the most recent calendar year?

A. The following exhibits reconcile the projected test year to the historical year:

i. Exhibit A-11 (HLR-30), Schedule A-3;
ii. Exhibit A-12 (HLR-34), Schedule B-4;
iii. Exhibit A-13 (HLR-37), Schedule C-1.1;
iv. Exhibit A-13 (HLR-41), Schedule C-5; and
v. Exhibit A-13 (HLR-42), Schedule C-5.1.

[1] 2.1% based on a 10-month proration to align with the October 31, 2026 projected test year.

Q. Please explain Exhibit A-11 (HLR-29), Schedule A-2.

A. This exhibit presents the financial metrics for the projected test year as required by the Filing Requirements. Column (b) shows metrics assuming no rate relief is granted. Column (c) shows metrics assuming the full rate relief request is granted.

Q. Please explain Exhibit A-11 (HLR-30), Schedule A-3.

A. This exhibit presents a comparison of the historical and projected year revenue deficiency for Consumers Energy. Column (d) of the exhibit presents rate base and rate of return amounts for the historical year. Column (e) shows the changes resulting from adjustments as supported by the various Company witnesses that were made in developing the projected test year revenue requirement. Column (f) shows the rate base, income requirement, and revenue requirement for the projected test year.

Q. What are the major differences between the historical year and the projected test year results shown on Exhibit A-11 (HLR-30), Schedule A-3?

A. The comparison of historical and projected results in Exhibit A-11 (HLR-30), Schedule A-3, shows that rate base increases by approximately $2.3 billion (line 7) and the rate of return increases from 5.85% to 6.22% (line 8). In addition, adjusted NOI (line 10) decreases by approximately $16.2 million from the historical year to the projected test year.

Q. Please describe Exhibit A-12 (HLR-31), Schedule B-1.

A. Exhibit A-12 (HLR-31), Schedule B-1, is a summary presentation of the projected test year rate base. The total rate base for the 12 months ending October 31, 2026 is approximately $11.8 billion as disclosed on line 8.

Q. Please describe Exhibit A-12 (HLR-32), Schedule B-2.

A. Exhibit A-12 (HLR-32), Schedule B-2, shows the total utility plant for the projected test year. The total on line 25 is carried forward to line 1 on Exhibit A-12 (HLR-31), Schedule B-1.

Q. Please describe how the projected test year average utility plant and related amounts were developed.

A. Utility plant and reserve balances for the projected test year were developed by calculating a 13-month average of the balances from October 31, 2025 through October 31, 2026. Actual calendar year 2023 balances for construction work-in-progress ("CWIP"), gross plant, and accumulated provision for depreciation were used as the starting point. Projected capital expenditures (including Allowance for Funds Used During Construction ("AFUDC")) and plant additions were added for the calendar year 2023, calendar year 2024, and for the ten months ending October 31, 2026; followed by adjustments for projected retirements, depreciation expense, cost of removal, the calculation of the ending balances for CWIP, plant, and the accumulated provision for depreciation.

Q. Please describe Exhibit A-12 (HLR-33), Schedule B-3.

A. Exhibit A-12 (HLR-33), Schedule B-3, presents the depreciation reserve for the projected test year by functional group. The total on line 18 is carried forward to line 2 on Exhibit A-12 (HLR-31), Schedule B-1. The increase in projected depreciation reserve incorporates projected depreciation expense from Exhibit A-13 (HLR-43), Schedule C-6, which I describe later in my testimony.

Q. Please explain Exhibit A-12 (HLR-34), Schedule B-4.

A. Exhibit A-12 (HLR-34), Schedule B-4, develops the Company's proposed projected test year working capital. The starting point for this exhibit is the historical year working capital (column (b)), which is adjusted to reflect the 13-month average June 2024 ending balances shown in column (d), the most current study practical for inclusion at the time of assembling the case. The June 2024 average balances are then adjusted to reflect changes to:

i. cash based on projections sponsored by Company witness Bleckman;

ii. gas stored underground as sponsored by Company witness Timothy K. Joyce and the corresponding adjustment to accounts payable;

iii. prepaid cloud computing balances sponsored by Company witness Stacy H. Baker;

iv. pension and other post-employment benefits ("OPEB") balances based on projections sponsored by Company witness Kendra K. Grob;

v. the regulatory asset and liability related to the pension and OPEB volatility mechanism;

vi. accrued tax balances;

vii. deferred debits for a Standardization Engineering Analysis adjustment sponsored by Company witness Michael P. Griffin;

viii. the regulatory asset related to the projected loss on the sale of the Riverside Storage Facility discussed below in Section III of my testimony; and

ix. deferred debits for a software implementation deferral as sponsored by Company witness Baker.

Q. Why did the Company use the Balance Sheet Method in determining working capital?

A. Use of the Balance Sheet Method was mandated by the MPSC in Case No. U-7350. The Filing Requirements also require that this method be used to develop the allowance for working capital.

Q. Please describe Exhibit A-12 (HLR-35), Schedule B-5.

A. Exhibit A-12 (HLR-35), Schedule-B-5, provides a summary of capital spending as supported by Company witnesses Baker, Corey E. Ballinger, Jessica R. Byrom, Matthew J. Foster, Griffin, Quentin A. Guinn, Joyce, Kristine A. Pascarello, and Lincoln D. Warriner. This exhibit provides capital spending for the bridge years and the projected test year as well as the projected test year capital spending in the Company's previous gas rate case, Case No. U-21490.

Q. Please describe Exhibit A-13 (HLR-36), Schedule C-1.

A. Exhibit A-13 (HLR-36), Schedule C-1, presents the calculation of adjusted NOI for the projected test year of $545.5 million as shown on line 22. Total operating revenues (line 4) are netted against total operating expenses (line 16) to arrive at net operating income on line 17. Further adjustments are made on lines 18, 20, and 21, which utilize normal ratemaking practices to arrive at adjusted NOI on line 22.

Q. Please explain Exhibit A-13 (HLR-37), Schedule C-1.1.

A. Exhibit A-13 (HLR-37), Schedule C-1.1, presents the reconciliation of historical year NOI to projected test year NOI. The exhibit presents revenues in columns (c) through (e), expenses in columns (f) through (p), NOI in column (q), AFUDC in column (r), and adjusted NOI in column (s). The exhibit begins with the historical year on line 1, normalizing adjustments to the historical year on lines 2 through 17, and projected test year adjustments on lines 18 through 32. Total adjusted NOI for the projected test year is shown on line 33, column (s). In general, the revenue and expense adjustments are shown with their accompanying tax impacts to arrive at the adjusted NOI. The historic year NOI of

$473.1 million on line 1, column (s), ties to the historic NOI on line 19 of Exhibit A-3 (HLR-9), Schedule C-1.

Q. Please explain the adjustments on Exhibit A-13 (HLR-37), Schedule C-1.1.

A. The adjustments on lines 2 through 16 are made to comply with prior Commission orders and follow traditional ratemaking adjustments to historical results such as: (i) removing regulatory disallowances; (ii) normalizing for unusual, one-time, or out-of-period items; (iii) bringing certain revenues and expenses “above the line”; (iv) adjusting historical revenues to reflect “normal” weather; and (v) adjusting income taxes. Additional adjustments include certain O&M expense normalizations to better align the historic year with expected expense amounts in the projected test year. These adjustments are supported by my exhibits, supporting workpapers, and the exhibits of other Company witnesses.

The historical year adjusted NOI on Exhibit A-13 (HLR-37), Schedule C-1.1, line 17, column (s), of $561.7 million ties to the adjusted NOI on Exhibit A-3 (HLR-9), Schedule C-1, line 36.

Q. How were the projected test year adjustments on Exhibit A-13 (HLR-37), Schedule C-1.1, developed?

A. These adjustments represent the movement from the historical year adjusted NOI to the projected test year adjusted NOI. The adjustments on lines 18 through 32 are developed from my exhibits and supporting workpapers and from the exhibits of Company witnesses Ahmed, Baker, Amy M. Conrad, Foster, Griffin, Grob, Guinn, Joyce, Pascarello, James P. Pnacek, and Brian J. Vanblarcum. The projected test year adjusted NOI on line 33 is the result of netting the projected test year adjustments on lines 18 through 32 against the historical year adjusted NOI on line 17. The projected test year adjusted NOI of

$545.5 million on line 33, column (s), ties to the projected test year adjusted NOI on Exhibit A-13 (HLR-36), Schedule C-1, line 22.

Q. Please explain the projected test year adjustments on Exhibit A-13 (HLR-37), Schedule C-1.1.

A. Lines 18, 19, and 21 represent the changes in gross margin from the adjusted historical year to the projected test year and are supported by Company witness Ahmed.

Line 20 represents the change in other revenues from the adjusted historical year to the projected test year and are supported by my workpapers.

Lines 22 and 23 represent the change in lost and unaccounted for ("LAUF") and company use gas, respectively, and are supported by Company witness Joyce.

Line 24 represents the change in other O&M expenses from the adjusted historical year to the projected test year and are supported by Company witnesses Baker, Byrom, Conrad, Foster, Griffin, Grob, Guinn, Joyce, Pascarello, and Pnacek. The adjustments on lines 22 through 24 are expanded on Exhibit A-13 (HLR-41), Schedule C-5 and Exhibit A-13 (HLR-42), Schedule C-5.1.

Line 25 represents the change in the book depreciation expense from the adjusted historical year to the projected test year. As stated above, the Company used the approved book depreciation rates, projected capital expenditures, and assumed plant retirements to determine the depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense for the projected test year.

Line 26 represents the change in MGP amortization expense from the adjusted historical year to the projected test year, which is supported by Company witness Foster, the amortization of the pension and OPEB volatility mechanism, which is supported on

Exhibit A-92 (HLR-51), and the projected amortization of the Riverside Storage Field regulatory asset, Exhibit A-12 (HLR-34), Schedule B-4.

Line 27 represents an adjustment to real and personal property tax to the projected test year amount supported by Company witness VanBlarcum and shown on Exhibit A-13 (HLR-44), Schedule C-7, line 1.

Line 28 represents the change in historical year payroll and other general taxes to the projected test year amount as shown on Exhibit A-13 (HLR-44), Schedule C-7, lines 6 and 15.

Line 29 represents the impact of City Income Tax (“CIT”). The projected test year CIT expense is shown on Exhibit A-13 (HLR-47), Schedule C-10.

Line 30 reflects the impact of Michigan Corporate Income Tax (“MCIT”). The projected test year MCIT expense is shown on Exhibit A-13 (HLR-46), Schedule C-9.

Line 31 represents the Federal Income Tax (“FIT”) adjustments which result from the other changes in revenues and expenses in the projected test year. Line 31 also reflects the differences between the FIT expense calculated at the current federal statutory rate and the actual total income tax expense. The projected test year FIT expense is shown on Exhibit A-13 (HLR-45), Schedule C-8.

Line 32 represents an adjustment to AFUDC from the adjusted historical year to the projected test year. The projected test year AFUDC is shown on Exhibit A-13 (HLR-48), Schedule C-11. AFUDC is an accounting convention that recognizes the costs, both interest and equity, of financing certain construction projects. The recognition is through the transfer of interest and equity cost from the income statement to CWIP on the balance sheet. The interest and equity costs are capitalized in the same manner as construction labor and material costs when the project is closed to plant-in-service. The criteria for applying AFUDC to a construction project require on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000.

Q. Please describe Exhibit A-13 (HLR-38), Schedule C-2.

A. Exhibit A-13 (HLR-38), Schedule C-2, shows the development of the revenue conversion factor for the projected test year. The revenue conversion factor converts a utility's after-tax income deficiency (or sufficiency) into the required pre-tax revenue requirement. For the projected test year, the FIT rate is 21.00%, the MCIT rate is 5.24%, and the CIT rate is 0.16%, which results in a revenue conversion factor of 1.3381.

Q. Please explain Exhibit A-13 (HLR-39), Schedule C-3.

A. Exhibit A-13 (HLR-39), Schedule C-3, presents the total operating revenues for the projected test year. Line 1 and line 2 of this exhibit present the sales and transportation revenue supported by Company witness Ahmed. Line 3 presents the other revenues supported by my workpapers. The total on line 4 is carried forward to the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

Q. Please explain Exhibit A-13 (HLR-40), Schedule C-4.

A. Exhibit A-13 (HLR-40), Schedule C-4, presents the cost of gas sold for the projected test year. The projected test year cost of gas sold is supported by Company witness Ahmed. This total is carried forward to line 5 of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

Q. Please explain Exhibit A-13 (HLR-41), Schedule C-5.

A. Exhibit A-13 (HLR-41), Schedule C-5, presents the other O&M expenses for the projected test year as compared to the historical year. The amounts on lines 1 through 26 were provided by Company witnesses Baker, Byrom, Conrad, Foster, Griffin, Grob, Guinn, Joyce, Pascarello, and Pnacek and are supported in their direct testimony and exhibits. Lines 27 through 30 are supported by my workpapers. LAUF gas (line 1), company use gas (line 2), and total O&M expense (line 34) are carried forward to lines 6, 7, and 8, respectively, of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

Q. Please explain Exhibit A-13 (HLR-42), Schedule C-5.1.

A. Exhibit A-13 (HLR-42), Schedule C-5.1, provides a summary of inflation and merit increases included in other O&M expense. Amounts projected using a method other than inflation and merit are included in column (g). The amounts on lines 1 through 26 were provided by Company witnesses Baker, Byrom, Conrad, Foster, Griffin, Grob, Guinn, Joyce, Pascarello, and Pnacek and are supported in their direct testimony and exhibits. Lines 27 through 30 are supported by my workpapers.

Q. Please explain Exhibit A-13 (HLR-43), Schedule C-6.

A. Exhibit A-13 (HLR-43), Schedule C-6, presents depreciation by functional grouping and amortization expenses for the projected test year. The total on lines 18 and 21 are carried forward to lines 9 and 10 of the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1. The calculated depreciation expense and associated accumulated provision for depreciation presented uses the book depreciation rates approved by the Commission as follows:

1. the Settlement Agreement in Case No. U-21176 dated September 8, 2023 for gas utility plant balances; and
2. the Order in Case No. U-20849 dated December 9, 2021 for common utility plant.

Book depreciation expense was developed by applying the functional composite book depreciation rates to the average projected test year depreciable plant balances.

Q. Does the Company have a depreciation rate case pending before the Commission that could impact depreciation expense and therefore, the revenue deficiency in this proceeding?

A. No.

Q. Please explain Exhibit A-13 (HLR-44), Schedule C-7, through Exhibit A-13 (HLR-48), Schedule C-11.

A. These exhibits present the following: (i) projected general taxes; (ii) projected FITs; (iii) projected state income taxes; (iv) projected other (or local) taxes; and (v) projected AFUDC. The total from each schedule is carried forward to the Company's projected adjusted NOI presentation on Exhibit A-13 (HLR-36), Schedule C-1.

Q. Please describe Exhibit A-13 (HLR-49), Schedule C-12.

A. Exhibit A-13 (HLR-49), Schedule C-12, shows the calculation of pro forma interest expense for the projected test year and the corresponding impact on income taxes.

Q. Please describe Exhibit A-13 (HLR-50), Schedule C-13.

A. Exhibit A-13 (HLR-50), Schedule C-13, shows the calculation of the tax effect of the interest synchronization adjustment for the projected test year and the corresponding impact on income taxes.

Q. Why are Exhibit A-13 (HLR-49), Schedule C-12, and Exhibit A-13 (HLR-50), Schedule C-13, included in the presentation?

A. The purpose of these exhibits is to align the interest expense and the associated tax benefits in the projected test year with the amount of rate base that is financed with debt and display the alignment in a transparent manner.

III. RATE IMPACT FROM THE SALE OF THE RIVERSIDE STORAGE FIELD

Q. Does the Company's execution of a Purchase and Sale Agreement for the Company's Riverside Storage Field have an impact on this case?

A. Yes. The Company executed a Purchase and Sale Agreement for the sale of the Riverside Storage Field in October 2024. As discussed by Company witness Joyce, the Company expects the sale to close before the end of 2025. Therefore, the historical net book value of this asset has been removed from this case.

The Company's current expectation is that the sale will result in a $8.9 million loss. In Case No. U-21656, the Commission approved the Company's request for cost deferral accounting and a regulatory asset for the loss associated with the sale of the Riverside Storage Field. Therefore, as previously discussed, the Company has made a projection adjustment to working capital to reflect the regulatory asset balance for the test year. The Company is requesting to amortize the regulatory asset over a three-year period.

The Company has used its best estimate of the Riverside loss to reflect the impacts within the instant case; however, actual transaction costs and customary closing adjustments may ultimately change the amount of the recorded loss. Therefore, the Company proposes to adjust the associated amortization expense in future gas rate cases to reflect any necessary adjustments for the actual realized loss on the Riverside storage field.

IV. ACCOUNTING TREATMENT FOR MAOP RETESTING COSTS TO COMPLY WITH NEW FEDERAL SAFETY STANDARDS

Q. Should the Commission allow the Company to adopt the accounting for MAOP retesting costs as approved by FERC in Docket No. AI20-3-000?

A. Yes. In June 2020, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued its final rule that addressed, among other items, the safety of gas transmission pipelines, including actions an operator must take to reconfirm the MAOP of natural gas pipelines not yet tested using the new federal safety regulations.[2]

As a result, FERC provided accounting guidance[3] stating that if a utility is required to retest the pipeline so that its full capacity can be utilized, such first-time and one-time retesting costs can be capitalized. When such retesting costs are capitalized, all prior testing costs related to the specific property should be retired. Based on this guidance, the Company is requesting approval to capitalize first-time and one-time retesting costs incurred due to the new FERC standard. Any related prior capitalized testing would be retired. Please see Company witness Griffin's testimony for further discussion related to the PHMSA transmission safety rules.

Q. Does this complete your direct testimony?

A. Yes.

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[2] *Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments*, 84 Fed. Reg. 51480 (October 1, 2019).
[3] June 23, 2020 FERC Docket No. AI-20-3-000, effective July 1, 2020.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

S. AUSTIN SMITH

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is S. Austin Smith, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am a Senior Rate Analyst in the Cost and Pricing Section of the Rates and Regulation Department.

Q. Please state your educational background and work experience.

A. I received a Bachelor of Business Administration degree with an emphasis in Accounting in April 2014 from Alma College. In Spring 2019, I earned a Master of Business Administration degree from Spring Arbor University. In August 2016, I began employment as a Rates Analyst in the Pricing Section of the Legal, Rates & Regulatory Department at Consumers Energy. My responsibilities include preparing various electric and gas rate analyses, rate design, research, and validating electric and gas charges as part of the Company's billing process. In September 2024 I was promoted to my current position.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have filed testimony in the following cases:

Case No. U-17771	(Amended) Energy Optimization Plan,
Case No. U-18261	Energy Waste Reduction ("EWR") Plan,
Case No. U-18331	EWR Reconciliation,
Case No. U-20028	EWR Reconciliation,

Case No. U-20275	Electric Self-Implementation Reconciliation,
Case No. U-20356	Gas Revenue Decoupling Reconciliation,
Case No. U-20671	Gas Revenue Decoupling Reconciliation,
Case No. U-21205	EWR Reconciliation,
Case No. U-21233	Demand Response Reconciliation,
Case No. U-21344	Gas Revenue Decoupling Reconciliation,
Case No. U-21410	Demand Response Reconciliation,
Case No. U-21490	General Gas Rate Case, and
Case No. U-21784	Residual Balance of Voluntary Refund Mechanism.

Q. What is the purpose of your direct testimony in this case?

A. The purpose of my direct testimony is to present the Company's proposed rate design, which collects the proposed revenue requirement from customers in an equitable manner reflecting the cost of providing service and taking into consideration rate impacts.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-16 (SAS-1)	Schedule F-2	Summary of Present and Proposed Revenue by Rate Schedule;
Exhibit A-16 (SAS-2)	Schedule F-2.1	Summary of Present and Proposed Rates by Rate Schedule;
Exhibit A-16 (SAS-3)	Schedule F-2.2	Calculation of Rate Design Targets;
Exhibit A-16 (SAS-4)	Schedule F-3	Present and Proposed Revenue Detail;
Exhibit A-16 (SAS-5)	Schedule F-4	Comparison of Present and Proposed Monthly Bills;
Exhibit A-108 (SAS-6)		Development of Rates for Transportation ATL Services;

Exhibit A-93 (SAS-7)	Calculation of Test Year Discount and Carrying Cost Rates for the Customer Attachment Program; and
Exhibit A-94 (SAS-8)	Calculation of Home Products Credit.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. SUMMARY OF PROPOSED RATE DESIGN CHANGES

II. ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY

III. TRANSMISSION ONLY TRANSPORTATION SERVICE RATE

IV. TYPICAL BILLS

V. CUSTOMER ATTACHMENT PROGRAM DISCOUNT AND CARRYING COST

VI. HOME PRODUCTS CREDIT CALCULATION

I. SUMMARY OF PROPOSED RATE DESIGN CHANGES

Q. Please describe Exhibit A-16 (SAS-1), Schedule F-2.

A. Exhibit A-16 (SAS-1), Schedule F-2, provides a summary of the proposed changes in revenue by rate schedule. The proposed change is derived from the calculated difference between test year present revenue and proposed revenue that incorporate the Company's revenue deficiency. The present and proposed revenues shown in Exhibit A-16 (SAS-1), Schedule F-2, are calculated by applying the test year billing determinants provided by Company witness Mustafa Ahmed to present rates, as well as to the rates being proposed by the Company in this case.

Q. What rates were used to calculate present revenue?

A. The Company applied the rates approved by the Commission in the MPSC Case No. U-21490 July 23, 2024 Order Approving Settlement Agreement ("July 23 Order") to the test year billing determinants to calculate present revenue in Exhibit A-16 (SAS-1), Schedule F-2.

Q. Please describe the Company's objectives and approach to rate design in this case.

A. Generally, the Company has designed rates so that the revenue recovered from each customer class reflects the adjusted costs for that class in the Company's test year Cost of Service Study ("COSS"). The Company also considers: (i) establishing rates that promote efficient use of the Company's gas system and promoting energy efficiency; (ii) establishing rates that promote a favorable business climate; and (iii) designing rates that provide the Company with a fair opportunity to collect its revenue requirements. The proposed gas delivery revenue and associated rate increases/(decreases) for each rate class are shown on Exhibit A-16 (SAS-1), Schedule F-2, page 2.

Residential Rates

The Company is proposing to maintain its existing residential rate structure for Rate Schedules A and A-1, which includes a fixed monthly customer charge and volumetric distribution charges. The proposed increase in distribution for Rates A and A-1 is 17.8% and 11.5% respectively, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 2. The total proposed increase for the residential class is 12.1% when including the forecasted cost of the gas commodity, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 1.

General Service Rates

The Company is proposing to maintain its existing rate structure for General Service Rate Schedules GS-1, GS-2, and GS-3. The proposed increase in distribution for the General Service rate class is 7.4%, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 2. The total proposed increase for the General Service class is 4.5% when including the forecasted cost of the gas commodity, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 1. The proposed rates maintain the currently established economic breakeven points between the General Service Rate Schedules, GS-1, GS-2, and GS-3.

Transportation Rates

The Company is proposing to maintain its existing transportation rate structure with Rate Schedules ST, LT, XLT, and XXLT. The proposed increase for the Transportation rate class is 26.9%, as shown on Exhibit A-16 (SAS-1), Schedule F-2, page 1. The proposed rates maintain the currently established economic breakeven points between the Transportation Rate Schedules ST, LT, and XLT. The Company is also proposing to modify its existing Transmission Only Transportation Service Rate.

Q. Is the Company proposing to discontinue and close Rate GL?

A. Yes. As noted by Company witness Kirkland D. Harrington, Rate GL will have no remaining customers by November 1, 2025.

II. ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY

Q. Please describe Exhibit A-16 (SAS-3), Schedule F-2.2.

A. Exhibit A-16 (SAS-3), Schedule F-2.2, shows the calculation of the revenue targets used for designing rates, including proposed adjustments, to the test year revenue requirement by rate schedule. The exhibit illustrates test year revenues based on the Company's test year COSS (Version 2), as shown in Exhibit A-16 (SMG-2), Schedule F-1.1. This is followed by the Company's proposed adjustments to the COSS, which results in the revenue target used for designing the Company's proposed rates.

Q. How did the Company develop the test year revenue targets for each class shown on Exhibit A-16 (SAS-3), Schedule F-2.2?

A. As shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 1, the Company started with the test year COSS. The COSS was adjusted for the Residential Income Assistance ("RIA") provision and the Low-Income Assistance Credit ("LIAC") to assign cost responsibility for these assistance programs to all rate schedules, as shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 2. Furthermore, the COSS was adjusted to reflect the storage adjustment for Rate XXLT, as shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 3. Consistent with the methodology approved by the Commission in prior gas cases, the COSS was also adjusted to maintain economic breakeven points within the General Service and Transportation rate classes. In the interest of rate stability and to moderate rate impacts for customers on Rate GS-1, the Company is proposing to shift proposed revenue. Approximately $2.5 million has been shifted into Rate GS-2 from Rates GS-1 and Rate GS-3. Approximately $120,000 was shifted from Rate XLT to Rate LT. The adjusted cost of service was compared to the test year present revenue to determine the revenue deficiency by class. This deficiency was then adjusted for incremental late payments to determine the adjusted deficiency. The adjusted deficiency was added to the test year present revenue, resulting in the rate design targets by rate schedule as shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 11.

Q. How did the Company allocate the low-income credits associated with the RIA credit and LIAC?

A. The allocation of the RIA credit and LIAC is shown on Exhibit A-16 (SAS-3), Schedule F-2.2, page 2. The credits are allocated to each rate class based on that class's pro rata share of the total revenue requirement from the COSS.

Q. What is the basis for allocating the RIA credit and LIAC among all rate schedules?

A. The Company is maintaining the allocation ordered by the Commission in its June 3, 2010 Order in Case No. U-15985 (Michigan Consolidated Gas Company's gas general rate case) ("U-15985 Order"). The Order states:

> The ALJ found that the revenue shortfall should be recovered from all rate classes, on the basis of Allocation Factor No. 20 rather than on the basis of throughput. [U-15985 Order, page 91.]
>
> The Commission adopts the findings and recommendations of the ALJ. For the electric utilities, this shortfall is spread to all customer classes and the Commission is not persuaded that gas should be treated differently. See, MCL 460.11 (3). The Commission further finds that spreading it on the basis of cost of service plus the cost of gas is fair and reasonable. [U-15985 Order, page 92.]

Q. Please describe Exhibit A-16 (SAS-4), Schedule F-3.

A. Exhibit A-16 (SAS-4), Schedule F-3, calculates the test year proposed gas rates required to collect the revenue requirement derived from the test year calculation of rate design targets shown in Exhibit A-16 (SAS-3), Schedule F-2.2, page 1, line 11 for each rate schedule, based on the billing determinants provided by Company witness Ahmed. Both the present and proposed gas prices are applied to the billing determinants to calculate the test year revenue on Exhibit A-16 (SAS-1), Schedule F-2. The rates from this exhibit are the source of the proposed rates that appear in the redlined tariffs filed by Company witness Harrington in this case.

Q. How does the Company propose to design rates to recover the residential revenue requirement?

A. The Company calculated a residential customer charge using the methodology originally adopted by the Commission in MPSC Case No. U-4331, January 18, 1974 Order, page 30. This methodology limits the customer charge to only those costs associated directly with supplying service to a customer, such as costs associated with metering, the service lateral, and customer billing. Using this methodology, the Company calculated a residential customer charge of $21.96 per month.

Although the Case No. U-4331 methodology supports an increase of almost $7.00 to the Company's current residential customer charge, the Company proposes a residential customer charge for Rates A and A-1 of $20.00 per month. This proposal reflects a $5.00 increase from the current $15.00 residential customer charge. Using this approach, the Company can move the residential customer charge closer to the cost to serve while at the same time allow for a more gradual increase in the fixed charge. The increase in the customer charge also results in a corresponding increase to the low-income RIA monthly credit. The more revenue collected via the fixed customer charge, the greater the proportion of the RIA customer's bill is offset by the fixed monthly credit.

Q. Does the proposed increase in the residential customer charge result in a change to the volumetric distribution charge?

A. Yes. The proposed $5.00 increase in the customer charge results in a volumetric distribution charge of $5.8140. If the customer charge remained at $15.00, the distribution charge would be $6.4430.

Q. Will the increased residential customer charge increase bills for below-average users?

A. The average monthly consumption for a residential customer is 7.0 Mcf per month. With a $20.00 customer charge and $5.8140 distribution charge, a customer with below-average usage of 4.5 Mcf (for example) would only spend $26 more annually than if they had a $15.00 customer charge and $6.4430 distribution charge.

Q. Will the increased customer charge adversely affect customers who qualify for income assistance provisions?

A. No. In fact, customers qualifying for the RIA provision will see the benefit of lower bills, since the customer charge is completely offset by the RIA credit.

Q. Is the Company recommending a rate change to the Excess Peak Demand Charge for residential Rate A-1 customers?

A. Yes. The Excess Peak Demand Charge collects the higher metering costs associated with Rate A-1 customers; therefore, the Company proposes to increase this charge by the same percent increase as the residential customer charge. The proposed Excess Peak Demand Charge is shown on Exhibit A-16 (SAS-4), Schedule F-3, page 2, line 2, column (f).

Q. What is the Excess Peak Demand charge based on?

A. The Excess Peak Demand charge is based on the peak month's usage over 45 Mcf because January was the typical peak usage month for Rate A-1 customers, and 45 Mcf was the average peak monthly consumption for Rate A-1 customers when the charge was first established. The peak demand mark of 45 Mcf was first set in Case No. U-7650. In that filing, the Company testified that January was the typical peak usage month for Rate A-1 customers and 45 Mcf was the average peak monthly consumption for Rate A-1 customers in January 1982.

Q. Is the Company recommending a change to the Excess Peak Demand usage threshold of 45 Mcf?

A. Yes. The Company reviewed the most recent 12 months of consumption for Rate A-1 customers and found that February 2024 was the typical peak usage month and 76 Mcf was the average peak monthly consumption.

Q. Is the Company proposing to update Contiguous Charges for both General Service and Transportation customers?

A. Yes. Contiguous Charges have not been updated since U-20322 and are below the levels indicated by the Cost of Service Study. In the spirit of gradualism, the Company is proposing to increase the Contiguous Charges over several general rate case filings.

Q. How does the Company propose to set rates to recover the revenue requirement for the General Service Rate Schedules GS-1, GS-2, and GS-3?

A. Consistent with the July 23 Order, the Company is proposing principal customer charges, contiguous customer charges, and volumetric distribution charges to collect the proposed revenues. These rate changes maintain the economic breakeven points between Rate Schedules GS-1 and GS-2 at 1,000 Mcf annually and between Rate GS-2 and Rate GS-3 at 10,000 Mcf annually, as well as provide for the recovery of the annual revenue requirement for the General Service rate class. These rate changes are shown in Exhibit A-16 (SAS-2), Schedule F-2.1.

Q. How does the Company propose to set rates to recover the Transportation class's revenue requirement?

A. Consistent with the July 23 Order, the Company is proposing principal customer charges, contiguous customer charges, and distribution charges to collect the Transportation proposed revenues. The principal customer charges for ST and XXLT are set based on the COSS. The principal customer charges for LT and XLT are set to maintain the economic breakeven points. The Company proposes to update the contiguous customer charges from \$60 to \$105 for all ST, LT, and XLT contiguous accounts. These rate changes maintain the economic breakeven point between Rate ST and Rate LT at 100,000 Mcf annually and the breakeven point between Rate LT and Rate XLT at 500,000 Mcf annually, as well as provide for recovery of the annual revenue requirement for the Transportation class. Furthermore, as approved in the July 23 Order, the Company is maintaining Rate XXLT's minimum annual eligibility requirement of 4 Bcf. These rate changes are shown in Exhibit A-16 (SAS-2), Schedule F-2.1.

Q. Please explain economic breakeven points.

A. An economic breakeven point is the point of volumetric usage where revenue collected from one rate would equal revenue collected on a different rate.

Q. Is the Company proposing to reset the economic breakeven points?

A. No. The Company's proposed rates in this case maintain the breakeven points established in Case No. U-18124, and subsequently approved in Case No. U-18424, Case

No. U-20322, Case No. U-20650, Case No. U-21148, Case No. U-21308, and Case No. U-21490.

Q. Why does the Company strive to maintain economic breakeven points as part of the rate design?

A. Maintaining breakeven points allows for greater precision in revenue prediction and, therefore, greater accuracy in setting rates and minimizes confusion for customers. When economic breakeven points change, customers have an economic incentive to switch from their existing rate to a more economical rate. This can result in under- and over-recovery of costs if many customers shift rates. In addition, frequent shifts from rate to rate on a large scale can create volatility in revenues received by the Company. This makes it difficult to accurately predict future revenues for ratemaking and planning purposes. Maintaining economic breakeven points minimizes volatility by eliminating any economic incentive to change rates when the customer use has not changed, while simultaneously establishing cost-based rates for the General Service class. However, it may be necessary in certain circumstances to realign the breakeven points if the individual rate classes continue to move further from their cost-basis and maintaining the current breakeven points is no longer appropriate.

Q. The July 2023 order stated "In its next gas rate case filing, Consumers Energy will undertake two studies, with the participation and input of interested parties. The first study will examine the breakeven points and bringing the breakeven points and the customer charges closer to cost of service." How is the Company addressing the breakeven study in this filing?

A. The Company held a collaborative meeting with interested parties to discuss options for studying the breakeven points. We discussed setting the transportation customer charges to the cost of service and recalculating new breakeven points, resetting the breakeven points based on the natural breaks in billing frequency distribution, and eliminating breakeven points and establishing a declining block rate structure. We also discussed starting with the cost of service study to inform any change to the current breakeven points. Any change to the breakevens or rate structure will require aligning the sales forecast so that customers and their usage are reflected on the appropriate rate and informing customers that there may be a more economical rate option available to them.

Q. Is the Company proposing any changes as a result of this discussion?

A Not at this time. The Company has proposed transportation changes that align closely with the cost of service in this case and a change to the breakeven points was not needed. However, the Company will continue to evaluate the cost of service and propose future changes to the transportation rate structure and/or breakevens should the charges get out of line again.

Q. Please explain Authorized Tolerance Levels ("ATL").

A. An ATL is a percentage of a transportation customer's annual contract quantity ("ACQ"). The ATL is the percentage of the ACQ which the transportation customer can have in storage at the end of any given month without incurring additional Load Balance charges. The ACQ is based on the highest 12 consecutive months during the contract's 36-month lookback period. The ACQ is calculated either at the beginning of the contract or during the periodic review, which occurs every five years.

Q. Is the Company proposing changes to the ATLs offered?

A. No. Exhibit A-108 (SAS-6) provides the credit calculation, and Exhibit A-16 (SAS-4), Schedule F-3, provides the revenue calculation for each transportation rate class, consistent with the structure approved in the July 23 Order.

Q. Is the Company proposing changes to the transportation charge adjustment associated with the ATLs?

A. No. Consistent with the July 23 Order, the Company has directly adjusted the per Mcf storage cost based on the ratio of the ATL tiers and the weighted average ATL of 6.6%. This results in a cost per Mcf for each tier of ATL, including the 8.5% tier. The Company then adjusted each of the tiers by the 8.5% tier to keep the 8.5% tier as the neutral default level. Exhibit A-108 (SAS-6), provides this adjustment calculation.

Q. Is the Company proposing any other changes related to the 4.0% ATL adjustment for Rate XXLT?

A. No. Consistent with the July 23 Order, the Company has spread the 4.0% ATL adjustment given to Rate XXLT back to all other transportation rate schedules by directly adjusting the per Mcf storage cost based on the ratio of the ATL tiers and the weighted average ATL of 6.6%.

Q. In the development of Rate Design, does the Company separate Gas Customer Choice ("GCC") sales from Gas Cost Recovery ("GCR") sales?

A. No. The rate design calculates delivery charges for all customers. GCC and GCR customers pay the same delivery charges, thus there is no need to separate GCC sales from GCR sales. Only total sales are needed as separating them has no impact on rate design.

III. TRANSMISSION ONLY TRANSPORTATION SERVICE RATE

Q. Are you proposing any changes to the Transmission Only Transportation Service Rate?

A. Yes. Currently, the Transmission Only ("TOT") Rate offers one single rate – a volumetric charge of $0.4533 per Mcf. The Company is proposing to offer four rate options (STT, LTT, XLTT, XXLTT) that consist of both a Customer Charge and a volumetric Transmission Charge.

Q. How were the transmission only rates designed?

A. The Company designed a transmission only rate for small, large, extra-large, and extra extra-large service which follows the full-service transportation rate schedules. The transmission costs from the cost of service, as allocated to the transportation rate schedules, were divided by the corresponding transportation sales forecast to develop a per Mcf transmission cost, as shown on Workpaper WP-SAS-5.

Q. What change is the Company proposing to this design?

A. Consistent with the rate design structures proposed for full transportation service customers, the Company is proposing customer charges and transportation charges to collect revenues from Transmission-Only customers. The customer charges for STT and XXLTT are set based on the COSS. The principal customer charges for LTT and XLTT are set to maintain the economic breakeven points. These rate changes maintain economic breakeven points between Rate STT and Rate LTT at 100,000 Mcf annually and a breakeven point between Rate LTT and Rate XLTT at 500,000 Mcf annually, as well as provide for recovery of the annual revenue requirement for Transmission-related costs. Consistent with rate design proposed for full transportation service customers, and to maintain current approved breakeven points, the Company is proposing to shift proposed revenue between transmission-only rate schedules. Approximately $1.5 million has been shifted into Rates STT and LTT from Rate XLTT. Furthermore, to mirror the proposal for XXLT, the Company is proposing to maintain Rate XXLTT's minimum annual eligibility requirement of 4 Bcf. These rate changes are shown in Exhibit A-16 (SAS-2), Schedule F-2.1.

Q. How will the revenue from customers on this rate be treated?

A. The revenue from these customers will be included in Other Revenue and will serve as an offset to the Company's revenue requirement. This is consistent with how Act 9 customer revenue is treated today.

Q. Did the Company project any customer usage and revenue during the test year?

A. The Company does expect that some customers could take this rate during the test year given the termination dates of existing Act 9 contracts. However, the usage for the test year is expected to be minimal and the revenue will not be significantly different from what is included in other revenue for the Act 9 contracts today. Therefore, the Company did not make any adjustments to sales or revenue for this proposal.

IV. TYPICAL BILLS

Q. Please describe Exhibit A-16 (SAS-5), Schedule F-4.

A. Exhibit A-16 (SAS-5), Schedule F-4, provides the impacts resulting from the proposed gas rates and rate design changes for customers on each rate schedule at various usage levels. This exhibit is used to gauge the distribution of the rate impacts across the population of customers taking gas service under the various rate schedules.

V. CUSTOMER ATTACHMENT PROGRAM DISCOUNT AND CARRYING COST

Q. Please explain Exhibit A-93 (SAS-7).

A. Exhibit A-93 (SAS-7) provides the calculation of the test year discount and carrying cost rates for the Customer Attachment Program ("CAP") and is used to support the changes to the CAP tariff sheet sponsored by Company witness Harrington.

VI. HOME PRODUCTS CREDIT CALCULATION

Q. Please describe Exhibit A-94 (SAS-8).

A. The Settlement Agreement in Case No. U-21490 provides for the Company to share three fourths of the gain related to the Home Energy Products sale or $82,500,000 over a three-year period from October 1, 2024 through September 30, 2027 through the Home Products Credit. Exhibit A-94 (SAS-8) calculates a credit to each rate schedule to provide $27,500,000 over a twelve-month period effective on and after November 1, 2025 using the same methodology as approved in Case No. U-21490. Exhibit A-94 (SAS-8) shows the proposed volumetric credit per Mcf, by rate schedule. This was calculated using Company witness Ahmed's forecasted test year sales. The proposed refund was allocated to the customer classes using the allocation provided by Company witness Samuel M. Geller.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Brian J. VanBlarcum, and my address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am a Tax Director in the Company's Corporate Tax Department.

Q. Please briefly describe your educational background.

A. I am a graduate of Western Michigan University where I earned a Bachelor of Business Administration degree in Finance.

Q. Please describe your business experience.

A. I started with the Company in 2004 as a General Accounting Analyst with the Company's Property Accounting team. In 2019, I was appointed to my current position as Tax Director with the Company's Corporate Tax Department.

Q. Are you a certified assessor?

A. I am a Michigan Certified Assessing Officer certified by the State of Michigan's State Tax Commission and a member of the Michigan Assessors Association.

Q. What are your responsibilities as Tax Director?

A. I am responsible for the administration of the Company's real and personal property taxes. This includes: (i) managing the Company's self-declaration of personal property located within the state of Michigan; (ii) overseeing property tax matters concerning the Company's land, generating sites, and other real property; and (iii) supervising tax payments to approximately 1,500 taxing authorities. I am also responsible for the calculation of federal and state tax depreciation related to the Company's fixed assets and the associated deferred income taxes.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I sponsored testimony in the following cases:

- Gas Rate Case No. U-15506;
- Electric Rate Case No. U-15645;
- Electric Rate Case No. U-16191;
- Gas Rate Case No. U-16418;
- Electric Rate Case No. U-17087;
- Electric Rate Case No. U-17735;
- Gas Rate Case No. U-17882;
- Electric Rate Case No. U-17990;
- Gas Rate Case No. U-18124;
- Electric Rate Case No. U-18322;
- Gas Rate Case No. U-18424;
- Electric Rate Case No. U-20134;
- Gas Rate Case No. U-20322;
- Gas Rate Case No. U-20650;
- Electric Rate Case No. U-20697;
- Gas Rate Case No. U-21148;
- Electric Rate Case No. U-21224;
- Gas Rate Case No. U-21308;

- Electric Rate Case No. U-21389;
- Gas Rate Case No. U-21490; and
- Electric Rate Case No. U-21585.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony identifies the Property Tax Rate for the test year (12 months ending October 31, 2026) and explains how the rate was derived. I am also supporting the amount of test year excess deferred federal income taxes being returned to gas customers as a result of the Tax Cuts and Jobs Act of 2017 ("TCJA") and the Commission's September 26, 2019 Order in the Company's Calculation C Case No. U-20309.

Q. Have you prepared any exhibits to accompany your direct testimony?

A. Yes. I am sponsoring:

Exhibit A-99 (BJV-1)	Development of the Property Tax Rate for the Test Year; and
Exhibit A-100 (BJV-2)	Amortization of Excess Deferred Federal Income Taxes for the Test Year and Tax Reform Regulatory Liability & Amortization.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

<u>Development of the Property Tax Rate for the Test Year</u>

Q. What is the Property Tax Rate for the test year?

A. As indicated on Exhibit A-99 (BJV-1), page 1, line 16, the Property Tax Rate for the test year is 0.013998859.

Q. How did you calculate the Property Tax Rate for the test year?

A. The Property Tax Rate for the gas business was calculated using the Company's prorated Gas Property Tax Expense in Exhibit A-99 (BJV-1), page 1, line 10, divided by the total of the 2025 estimated year-end plant-in-service in Exhibit A-99 (BJV-1), page 1, line 11, plus one-half of the estimated 2025 Construction Work in Progress in Exhibit A-99 (BJV-1), page 1, line 14.

Q. What is included in the Gas Property Taxes Paid – 2025 Estimate on Exhibit A-99 (BJV-1), page 1, line 1?

A. The Consumers Energy 2025 taxes paid of $196.8 million on behalf of the gas portion of the business represents estimated property taxes to be paid in 2025.

Q. What is included in the Gas Property Taxes on 2025 Plant Investment on Exhibit A-99 (BJV-1), page 1, line 2?

A. The $17.2 million increase is the estimated property taxes on the 2025 net additions that will be included in the 2026 property tax liability. This is calculated by taking the capital additions, less retirements, times the first year State Tax Commission multiplier table value to recognize a depreciation allowance, which is then multiplied by the statutory reduction of 50% of true cash value to get the assessed value, then multiplied by Consumers Energy's composite millage rate of 50.1693 to obtain the estimated tax amount. This calculation is shown on Exhibit A-99 (BJV-1), page 2, line 9.

Q. What is included in the Gas Property Taxes on Real Property Taxable Value Increases – Inflation on Exhibit A-99 (BJV-1), page 1, line 3?

A. The $0.1 million increase for the Real Property Taxable Value relates to the Michigan Constitution of 1963, Article IX, Section 3, allowing local assessors to raise real property taxable values by the lesser of 5% or the Consumer Price Index ("CPI"). For 2026, the Company's property tax model assumes a CPI rate of 2.5%. This calculation is shown on Exhibit A-99 (BJV-1), page 3.

Q. What is the result of including the Gas Property Taxes on 2025 Plant Investment and the Gas Property Taxes on Real Property Taxable Value Increase on the estimated 2026 property tax amount paid by the gas business?

A. The result of including these additional items is an estimated 2026 property tax amount to be paid for the gas business of $214.1 million as shown on Exhibit A-99 (BJV-1), page 1, line 4.

Q. How is this paid amount converted to an expense amount?

A. Since the Company expenses property taxes based on the fiscal year of the taxing authorities, 50.0% of the 2025 estimated gas property tax payments for Consumers Energy is added to the 2026 estimated gas payments since that amount will be expensed in 2026, while subtracting 50.0% of the 2026 estimated gas payments that will be expensed in 2027, arriving at a total 2026 property tax expense of $205.4 million as shown on Exhibit A-99 (BJV-1), page 1, line 7.

Q. What is the next step in calculating the tax rate for the test year?

A. For the test year, property tax expense was prorated for the period November 1, 2025 through October 31, 2026 using a monthly budgeted sales percentage applied to the 2025 and 2026 estimated annual property tax expense amounts. The result of factoring property tax expense monthly for the test year is a prorated Gas Property Tax Expense of $201.2 million. The Prorated Property Tax Expense for the test year is divided by the 2025 estimated year-end plant-in-service plus one-half of 2025 Estimated Construction Work in Progress to arrive at an average tax rate of 0.013998859.

<u>Amortization of Excess Deferred Federal Income Taxes for the Test Year</u>

Q. On September 26, 2019, the Commission issued an Order in the Company's Calculation C Case No. U-20309. What specific issues did the September 26, 2019 Order in Case No. U-20309 address?

A. The Commission's September 26, 2019 Order in the Company's Calculation C Case No. U-20309 authorized the amount and time period under which the Company will refund to gas customers $451,588,000 of excess deferred federal income taxes as a result of the TCJA lowering the corporate income tax rate from 35% to 21%. As part of the settlement terms in Case No. U-21148, the Commission approved an adjustment to reduce this amount by $4,174,259 to correct an overstatement of the TCJA remeasurement. The Commission authorized three different amortization periods: (i) Protected plant balances over an amortization period determined using the average rate assumption method ("ARAM"), (ii) Non-Protected plant balances amortized over 44 years, and (iii) Unprotected non-plant balances amortized over 10 years. Exhibit A-100 (BJV-2), page 2, referenced as Exhibit A-6 (SBM-4) in Case No. U-20309, provides the projected annual amortization of these balances based on the periods approved by the Commission.

Q. What impact did the settlement terms in Case No. U-20650 have on the unprotected non-plant balance?

A. The settlement in Case No. U-20650 accelerated the amortization of the remaining unprotected, non-plant balance to the period October 1, 2021 through September 30, 2022. As of October 1, 2022, the regulatory liability balance has been fully refunded to customers. Therefore, no amortization has been included in this case.

Q. What additional amount of excess deferred taxes related to the TCJA has the Company proposed to charge to customers in this case?

A. As shown on Exhibit A-100 (BJV-2), page 1, line 22, the Company has proposed to charge an additional $2,540,000 of excess deferred taxes ($3,406,000 of regulatory asset after gross-up for taxes) in this case. This amount represents the Company's regulatory asset recorded as of year-end 2022 which was calculated as the difference between the actual amount of excess deferred taxes for the year and the estimated amount included in rates. The Company's most recently filed report to the Case No. U-20309 docket, which calculates the $3,406,000 regulatory balance, is included as Exhibit A-100 (BJV-2), page 3.

Q. Based on the Commission's September 26, 2019 Order in Case No. U-20309 and the additional amount described above, what amount of excess deferred federal income tax has the Company proposed to return to customers in this case?

A. Exhibit A-100 (BJV-2), page 1, provides a calculation of the test year excess deferred federal income taxes included in this case based on the periods approved by the Commission in Case No. U-20309. Overall, the Company reduced Federal Income Tax Expense for the test year by $2.043 million to reflect the amortization periods and amounts discussed above. This amount is shown on Company witness Heather L. Rayl's Exhibit A-13 (HLR-45), Schedule C-8, lines 43, 47, and 48 as TCJA Tracker – U-20309, TCJA Amortization – ARAM, and TCJA – Non ARAM.

Q. Are the excess deferred federal income tax amounts refunded to gas customers in the test year estimates or actuals?

A. The amounts included in this case are estimates as the Commission's September 26, 2019 Order in Case No. U-20309 requires an annual reconciliation of the actual amount of excess deferred federal income tax in a given year and the estimated amount included in rates. The Company will file this reconciliation in the Case No. U-20309 docket by March 31 of each year.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21806
distribution of natural gas and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

LINCOLN D. WARRINER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

December 2024

Q. Please state your name and business address.

A. My name is Lincoln D. Warriner, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your current position with Consumers Energy?

A. My current position is Senior Strategy Manager in the Gas Engineering and Supply Department.

Q. What are your responsibilities as Senior Strategy Manager?

A. I assist the Gas Engineering and Supply and Gas Operations departments with asset lifecycle oversight, guidance, and leadership of the Natural Gas Delivery Plan ("NGDP") development, implementation, recovery, and verification of results focused on the Company's investment and operation of gas distribution assets.

Q. Please describe your professional work experience?

A. I have been employed by Consumers Energy for more than 37 years. I was promoted to the position of Senior Strategy Manager in Gas Engineering and Supply during 2021. My experience with the Company is summarized as follows:

I began working for the Company in June 1987 as a Region Accountant at the Grand Rapids Service Center. While there, I performed various reviews of internal accounting control procedures and workflow processes. In 1989, I transferred to a similar position at the Lansing Service Center. In 1991, I took a position as a Management Systems and Planning Analyst in the Southern Region Administration and Planning Department. My primary responsibility in this position was to provide analytical support to region management on issues concerning Operating and Maintenance ("O&M") and construction budgets and other performance measurements. In February 1994, I took a position as an Administrative Supervisor responsible for the supervision of several administrative functions including region accounts payable, miscellaneous accounts receivable, cash receipts and disbursements, payroll, records center, and mail room operations. In February 1995, I transferred to the Electric Strategic Business Unit ("SBU") Planning Department, which was subsequently consolidated within the Rates and Business Support Department. In that department, I was responsible for coordinating the development of financial plans, budgets, analysis, and forecasts for the Electric SBU. My responsibilities expanded within the Rates and Business Support Department to include the electric deliveries and peak demand forecasts, as well as supervisory responsibility for the Company's electric revenue forecasts and gas deliveries forecasts. In October 2012, I accepted a new position supporting the Smart Energy Development Project by maintaining the project business case, evaluating the estimated costs and benefits of the project, partnering with operating departments to plan for the realization of project benefits, and providing analytical support for various regulatory filings. In January 2016, I accepted a new position as a Financial Benchmarking Analyst in the Economic Portfolio Management Section of the Distribution Operations, Engineering, and Transmission Department. In this roll, I supported the Company's strategic capital allocation, long-term financial planning, and annual budgeting and forecasting processes. In July 2017, my position transitioned into the Rate Case/Controls section of the Gas Strategy Department to provide support for Company witnesses with the development of testimony and exhibits and assist in responding to data requests that occur during audit and discovery phases of general rate cases. I was promoted to my current position in 2021 to assist with gas distribution asset strategy planning and implementation.

Q. Please describe your educational background.

A. I received a Bachelor of Science Degree in Business Administration with a major in Accounting from Central Michigan University in 1987. In 1994, I received a Master of Science in Administration Degree from Central Michigan University.

Q. Have you testified in other cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?

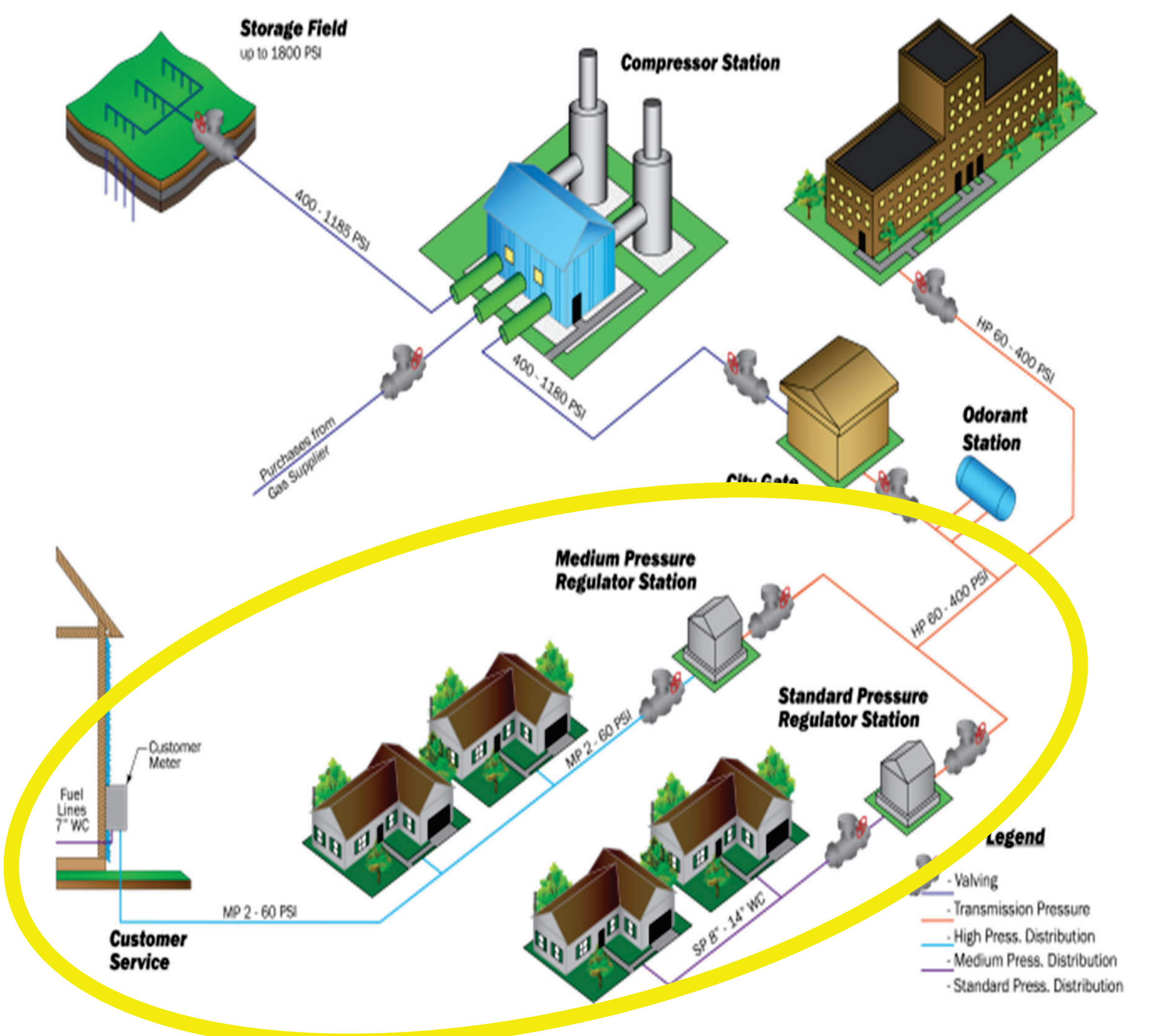
A. Yes. I have provided testimony in the following Case Nos.:

- Case No. U-16191 – January 2010 Electric Rate Case;
- Case No. U-16412 – September 2010 Energy Optimization Plan Amendment;
- Case No. U-16418 – August 2010 Gas Rate Case;
- Case No. U-16432 – September 2010 Power Supply Cost Recovery ("PSCR") Plan Case;
- Case No. U-16543 – February 2011 Renewable Energy Plan Amendment;
- Case No. U-16794 – June 2011 Electric Rate Case;
- Case No. U-16670 – August 2011 Energy Optimization Plan Amendment;
- Case No. U-16890 – September 2011 and February 2012 PSCR Plan Case;
- Case No. U-16924 – December 2011 Gas Cost Recovery Plan Case;
- Case No. U-17087 – September 2012 Electric Rate Case;
- Case No. U-17095 – September 2012 PSCR Plan Case;
- Case No. U-17429 – July 2013 Certificate of Necessity Filing for the Thetford Generating Plant;
- Case No. U-17643 – July 2014 Gas Rate Case;
- Case No. U-17735 – December 2014 Electric Rate Case;

- Case No. U-17882 – July 2015 Gas Rate Case;
- Case No. U-17990 – March 2016 Electric Rate Case;
- Case No. U-17087 Remand – June 2016 Remand Electric Rate Case;
- Case No. U-18124 – August 2016 Gas Rate Case;
- Case No. U-18322 – March 2017 Electric Rate Case;
- Case No. U-20134 – May 2018 Electric Rate Case;
- Case No. U-20697 – February 2020 Electric Rate Case;
- Case No. U-21308 – December 2022 Gas Rate Case; and
- Case No. U-21490 – December 2023 Gas Rate Case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to explain the Company's request for rate relief as it relates to certain gas distribution capital investments that are intended to keep the system safe and reliable while providing affordable and clean energy to customers. The distribution assets are the portion of the Company system that receives the gas at the outlet of the Company's city gates and delivers the gas to customers. In the diagram below, these assets are inside the yellow highlighted section.



The capital expenditures described in my testimony are primarily related to the installation and replacement of the Company's gas mains, services, and meters downstream of the city gates. These investments will support the continued safe delivery of gas to customers through this infrastructure. I will also briefly discuss the information technology ("IT") projects that are critically important to support these gas functions within the Company. These IT projects are fully developed, presented, and supported by Company witness Stacy H. Baker.

Q. How does your direct testimony relate to the NGDP presented by Company witness Neal P. Dreisig?

A. Mr. Dreisig's direct testimony discusses the Company's NGDP. My direct testimony contains elements that support the objectives of the NGDP: providing gas supply that is safe, reliable, affordable, and clean. The distribution capital programs represented in my direct testimony work toward achieving the NGDP's objectives of providing safe and reliable service to both new and existing customers within the Company's natural gas service area.

Q. How does the scope of your testimony compare to the testimony you provided in the Company's last gas rate case (Case No. U-21490)?

A. The capital programs described in my testimony are the same as the capital programs I sponsored in Case No. U-21490.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (LDW-1)	Schedule B-5.9	Projected Capital Expenditures, Distribution Plant, Summary of Actual & Projected Gas and Common Capital Expenditures;
Exhibit A-101 (LDW-2)		Actual & Projected Gas Capital Expenditures - New Business Program;
Exhibit A-102 (LDW-3)		Actual & Projected Gas Capital Expenditures - Asset Relocation Program;
Exhibit A-103 (LDW-4)		Actual & Projected Gas Capital Expenditures - Regulatory Compliance Program;
Exhibit A-104 (LDW-5)		Actual & Projected Gas Capital Expenditures – Capacity/ Deliverability Program; and

Exhibit A-105 (LDW-6)	Projected Capital Expenditures – Transmission & Distribution Plant, Summary of Actual & Projected Gas Capital Expenditures.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. Please summarize your direct testimony.

A. My direct testimony explains the Company's projections of certain Gas Distribution capital program investments through October 31, 2026, which are displayed on Exhibit A-12 (LDW-1), Schedule B-5.9. The total Gas Distribution capital expenditures supported by this direct testimony are as follows:

- Calendar year 2023 actual capital expenditures of $212,938,276, as displayed on line 5, column (b), of Exhibit A-12 (LDW-1), Schedule B-5.9;
- Calendar year 2024 projected capital expenditures of $204,595,685, as displayed on line 5, column (c), of Exhibit A-12 (LDW-1), Schedule B-5.9;
- Ten months ending October 31, 2025 projected capital expenditures of $227,215,170, as displayed on line 5, column (d), of Exhibit A-12 (LDW-1) Schedule B-5.9; and
- Projected test year 12 months ending October 31, 2026 capital expenditures of $321,119,320, as displayed on line 5, column (f), of Exhibit A-12 (LDW-1), Schedule B-5.9.

These expenditures are also shown in Table 1 below.

Table 1: Gas Distribution Capital Expenditures (in thousands of dollars)

Program Description	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
New Business	76,320	65,048	52,654	117,702	66,645
Asset Relocation	97,685	86,838	75,838	162,676	98,809
Regulatory Compliance	34,488	45,217	91,704	136,920	150,311
Capacity/Deliverability	4,446	7,493	7,019	14,512	5,354
Total Capital	**212,938**	**204,596**	**227,215**	**431,811**	**321,119**

I. GAS DISTRIBUTION CAPITAL EXPENDITURES

Q. Please highlight the change in test year capital expenditures compared to the historical actual capital expenditures incurred by the Company in calendar year 2022.

A. The projected test year capital expenditures of $321.119 million are $108.181 million more than the $212.938 million actually incurred in calendar year 2023. The increase or decrease for each program is summarized below:

- New Business: a decrease of $9.675 million, or approximately 12.7%;
- Asset Relocation: an increase of $1.124 million, or approximately 1.2%;
- Regulatory Compliance: an increase of $115.823 million, or approximately 335.8%; and
- Capacity/Deliverability: an increase of $0.908 million, or approximately 20.4%.

As indicated above, the increase in Regulatory Compliance expenditures accounts for most of the increase in test year capital expenditures compared to the 2023 historical actual.

Q. How much of a difference was there between the 2023 actual capital expenditures for these programs and the five-year average amount?

A. The 2019-2023 five-year average amount is $212.9 million, and the 2023 actual amount is $212.9 million, so the 2023 actual capital expenditures were approximately equal to the five-year average. Table 2 provides the actual capital expenditures for 2019 through 2023 for each program, as well as the corresponding five-year average amount.

Table 2: Gas Distribution Capital Expenditures – 5 Year History (in thousands of dollars)

Program Description	Historical 2019	Historical 2020	Historical 2021	Historical 2022	Historical 2023	Five Year Historical Average
New Business	86,498	87,021	55,373	74,088	**76,320**	**75,860**
Asset Relocation	106,363	83,973	63,376	116,504	**97,685**	**93,580**
Regulatory Compliance	46,318	38,354	46,994	22,832	**34,488**	**37,797**
Capacity/Deliverability	3,560	3,599	6,503	10,196	**4,446**	**5,661**
Total Capital	**242,739**	**212,947**	**172,246**	**223,620**	**212,938**	**212,898**

Q. Please summarize the change in test year capital expenditures compared to the historical five-year average actual capital expenditures incurred by the Company in 2019-2023.

A. The projected test year capital expenditures of $321.119 million are $108.221 million more than the historical five-year average amount of $212.898 million, which represents an increase of approximately 24%.

Q. Please describe the primary changes in test year capital expenditures compared to the historical actual capital expenditures incurred by the Company in 2019-2023.

A. The projected test year capital amount of $321.119 million exceeds both the 2023 historical actual and the historical five-year average. The increase can be attributed to five specific Regulatory Compliance projects that account for $103.1 million of the Company's projected test year capital expenditures. These include:

- $35.453 million of test year capital expenditures for the Line 1002c Macomb & Oakland County Maximum Allowable Operating Pressure ("MAOP") project;
- $33.175 million of test year capital expenditures for the Line 1022 Airport Road MAOP project;
- $17.430 million of test year capital expenditures for the Line 1093 Shattuck Road MAOP project;
- $9.031 million of test year capital expenditures for the Line 1026f Mt Hope Road MAOP project; and

- $8.042 million of test year capital expenditures for the Line 1009/1009c Phase 3 Little Mack - 10 mile to 9 mile, Macomb County MAOP project.

These specific projects are described in more detail within my testimony on the MAOP-Distribution sub-program.

Q. Please describe the approach used to project the Company's Gas Distribution capital expenditures for the years 2023 through the 12 months ending September 30, 2025.

A. The projected capital expenditures for this period are based on projected costs for individual projects and sub-programs necessary to ensure customer safety, meet regulatory requirements, and provide reliable service to customers. The projection methodologies vary among the different sub-programs and are described in more detail within each respective section throughout my direct testimony. The 2024 projections include actual expenditures for January through August of 2024 and estimates of expenditures for September through December of 2024. Projections of annual 2025 and 2026 capital expenditures were used in combination with historical spending patterns to estimate the dollars for the ten months ending October 31, 2025, and the test year period of November 1, 2025, through October 31, 2026. In a few instances, monthly estimates were made with input from subject matter experts if historical actual spending patterns did not provide a reasonable basis for estimating the timing of 2025 and 2026 expenditures.

Q. Please describe the Gas Distribution programs and sub-programs included within the scope of your testimony and exhibits.

A. The programs, as shown on Exhibit A-12 (LDW-1), Schedule B-5.9, are:

- New Business;
- Asset Relocation;

- Regulatory Compliance; and
- Capacity/Deliverability.

Each program includes sub-programs that provide additional detail for each program, as shown on Exhibit A-101 (LDW-2) through Exhibit A-105 (LDW-6):

- New Business
  - Mains, Services & Meter Stands – Distribution
  - Large New Business Projects – Distribution
  - Customer Attachment Program - Distribution
- Asset Relocation
  - Asset Relocation – Civic Improvement
  - Asset Relocation - Reimbursable
- Regulatory Compliance
  - Regulatory Base – Distribution
  - Meters
  - MAOP – Distribution
  - Cathodic - Distribution
- Capacity/Deliverability
  - Augment - Distribution

Many of these programs have a gas distribution and a gas transmission component to them. My direct testimony represents the gas distribution portion of these programs. The direct testimony of Company witnesses Michael P. Griffin, Neal P. Dreisig, and Timothy K. Joyce represent additional components of the gas transmission system as well as distribution regulating stations, compression, and storage systems. The direct testimony of Company witness Pascarello represents gas distribution system capital expenditures associated with the Company's Material Condition Program and the Gas Operations Other Program.

Q. Have you included contingency costs in the capital expenditures you are sponsoring?

A. No, there are not any contingency costs included in the capital expenditures.

A. New Business

Q. Please describe the capital expenditures related to the New Business Program as shown on Exhibit A-12 (LDW-1), Schedule B-5.9, line 1.

A. The New Business Program consists of the capital costs of adding new commercial, industrial, and residential customers to the Company's distribution system. The program costs include the cost of installing mains and services, and the cost of meter stands to service new customers. These projects are required in response to customer requests for new gas use at their site. Customers requesting a new connection are asked to pay for a portion of the cost to construct these projects. The amount paid by a customer is referred to as a "contribution in aid of construction" or "CIAC." The total New Business capital expenditures (net of customer contributions) that the Company experienced in 2023, and the Company's projections for the years 2024, the ten months ending October 31, 2025, and the 12-month test year ending October 31, 2026, are displayed in total on Exhibit A-12 (LDW-1), Schedule B-5.9 on line 1, columns (b) through (f), respectively. These expenditures are also shown in Table 3 below, with amounts for each sub-program identified.

Table 3: New Business Program Capital Expenditures (expressed in thousands of dollars)

Program Description	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
Mains, Services, Meter Stands	66,760	55,338	49,596	104,934	61,682
Large New Business Projects	9,371	9,710	3,058	12,768	4,963
Customer Attachment Program	188	0	0	0	0
Total New Business	**76,320**	**65,048**	**52,654**	**117,702**	**66,645**

Exhibit A-101 (LDW-2) provides further details of the expenditures included in this program.

Q. Please identify any regulatory standards related to the Company's gas new business connection process.

A. Michigan Administrative Code Section R 460.2371 contains safety and service quality standards for gas utilities. Specific provisions include:

- A utility shall establish gas service to a customer's premises in compliance with the Michigan gas safety standards; and
- If there is an existing main at a requesting address, a utility shall complete 90% or more of its new service installations within 15 business days of customer payment per tariff requirements and site readiness, or by a later date that is mutually agreed upon between the utility and customer.

The Company implemented plans during 2023 to address performance impacts associated with construction material delivery delays as well as other root causes of service installation delays. The Company's plans for improving performance results are detailed in the August 4, 2023 document filed in Case No. U-21458 titled "Consumers Energy Company's Report on Meter Malfunctions, Estimated Billing Practices, and Delays in New Service"[1]. The Company has been meeting the new gas service installation factor standard each month since June 2023.

Q. What is the Company's current projection for gas new business service connections?

A. The Company's projects 6,800 gas new business service connections during calendar year 2024 and again during calendar year 2025, then 7,000 gas new business service connections in 2026. The twelve-month ending October 31, 2026 test year forecast is 6,964 services.

[1] The referenced report is available on the Michigan Public Service Commission's website at the following location: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000094k46AAA

These projections are significantly reduced compared to the average for the 2019 through 2023 time period of 7,582 gas service installations. The variance between the test year projection and the five-year average is 618 services, or about 8.2% less than the five-year average.

Q. Please explain the growth in the Company's gas new business connection projections.

A. The Company's Customer Energy Management Department uses data from multiple sources to project and plan for new business growth.

Internal data regarding the installation of new gas services is one important source of data used to understand trends impacting the Company's investments in the new business program. During the five-year period of 2015 through 2019, the Company had experienced an average new gas service installation rate of approximately 9,100 new gas services installed per year.[2] 2019 was the last full year prior to the COVID-19 pandemic, and the Company installed 8,223 new gas service units in that year. During 2020, new gas service installations declined from 2019 by 987 units (or 12.0%) to 7,236 units.[3] During 2021, new gas service installations increased from 2020 by 625 units (or 8.6%) to 7,861 units. During 2022, new gas service installations declined by 142 units (or 1.8%) to 7,719 units. 2023 new gas service installations also declined 849 units (or 11.0%) compared to 2022. As a result, the Company has revised its long-range outlook for new gas service installation activity downward from prior forecasts.

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[2] Historical new gas service installations per year were: 2015 – 9,943; 2016 – 9,422; 2017 – 8,482; 2018 – 9,423; 2019 – 8,223. The average for these five years is calculated as (9,943+9,422+8,482+9,423+8,223)/5 = 9,098.6.

[3] As noted in the footnote above, new gas service installations in 2019 totaled 8,223 units.

The Customer Energy Management Department also monitors the projections of the Michigan Home Builders Association ("HBA of Michigan" or "HBA"). In January of 2024, the HBA of Michigan revised their projections of calendar year single family home permits to 14,330 units in 2023 and 13,964 units in 2024.[4] The 2023 unit projection was decreased by 1,216 units, or 7.8% from the HBA of Michigan's June 2023 forecast of 15,546 units for 2023.

The Company's projected service installations for 2024 and 2025 of 6,800 units reflect an anticipated decrease of 70 units compared to 2022, a decline of approximately 1.0%. Therefore, the service installation projections provided the Company's Customer Energy Management Department reflect slightly slower decline in 2024 than the HBA of Michigan projection.

The Company also subscribes to economic projections published by S&P Global ("S&P"). The Summary of the U.S. Economy, published by S&P is provided as a workpaper in this case by Company witness Heather L. Rayl.[5] The June 2024 forecast of total housing starts for the U.S. economy indicates an expectation that 2024 housing starts will be 1.373 million units, then increase slightly to 1.379 million units in 2025, and then increase to 1.400 million units in 2026. Despite the projected decline between 2023 and 2024, the 2024 to 2026 annual U.S. housing start forecasts all exceed the actual 2019

[4] Source: https://hbaofmichigan.com/assets/pdf/HBAM+2024+Permit+Forecast/ press release dated January 3, 2024, "2024 Production Forecast: Flat Market Continues"

[5] Workpaper reference: WP-HLR-33.

pre-pandemic measure of 1.292 million units as well as the 2016 to 2020 five-year average of 1.264 million units.[6]

Q. Do you have any further comment on the level of new business program activity that should be considered when evaluating the Company's projections of new business capital expenditures?

A. Yes. The Company's service installation projection includes customer conversions to natural gas under the Customer Attachment Program ("CAP"), which are expected to be relatively small in volume going forward, as well as new connections that are typically requested during building construction. Some of these new connections are expected to be located along existing gas main facilities, while others will require some extension of the distribution main network.

The Company experienced a significant increase in the amount of new business work associated with extending distribution mains in the 2023 historical year compared to the 2022 calendar year. The extension of distribution mains required investments of approximately $28.6 million during 2023. In comparison, the Company's investments to extend distribution mains were $18.1 million during the entire calendar year of 2022 and $11.7 during calendar year 2021. In addition to new residential subdivision developments, the Company has made investments to extend mains to a variety of customers, including the following examples:

- Battery Cell manufacturing and other manufacturing operations;
- Electricity generation operations;
- Renewable Natural Gas ("RNG") operations;
- Other agricultural facilities;

[6] Calculation of 2016-2020 average: [1.177 million units in 2016 + 1.205 million units in 2017 + 1.247 million units in 2018 + 1.292 million units in 2019 + 1.397 million units in 2020]/5 = 1.264 million units

- Manufactured home community developments; and
- Health care facility additions and expansions.

Q. Have the Company's current projections of New Business service attachments decreased from the projections provided by the Company in Case No. U-21490?

A. Yes, the new service attachment projections in this case are lower than the new service attachment projections in my testimony from Case No. U-21490. A comparison of New Business service attachments in each proceeding are provided below:

Table 4: New Business Program service attachment projections

Description	Historical 2023	Projected 2024	Projected 2025	Projected 2026
Case No. U-21490[7]	8,155	8,318	8,318	8,318
Current Projection (Case No. U-21806)	6,870	6,800	6,800	7,000
Difference (in units)	-1,285	-1,518	-1,518	-1,318
Difference (in percent)	**-15.8%**	**-18.2%**	**-18.2%**	**-15.8%**

Q. How many feet of gas distribution main have historically been installed as part of the Company's New Business Program?

A. During the time period of calendar years 2019 through 2023, the Company installed approximately 345.0 miles of gas main,[8] or an average of approximately 69.0 miles per year. The gas main installed during the 2023 historical year in this case is 68.1 miles, which is approximately 99% of the five-year average. During the January to September 2024 time frame, the Company installed 35.1 miles of distribution main and will likely

[7] Source: Case No. U-21490 Direct Testimony of Company witness Lincoln D. Warriner, page 17, Table 4.

[8] Historical gas main installation miles: 2019: 91.3 miles; 2020: 61.6 miles; 2021: 52.8 miles; 2022: 71.2 miles; 2023: 68.1 miles The five-year average is calculated as follows: (91.3 + 61.6 + 52.8 + 71.2+68.1)/5 = 345.0/5 = 69

install approximately 49 miles of distribution main for the full year of 2024, or approximately 71% of the five-year average.[9]

Q. What was the actual average New Business Program cost per service installed during the 2023 historical year?

A. I have calculated the average New Business Program cost per service installed during 2023 to be $9,745.01. This number was calculated using the total 2023 actual New Business Program capital expenditures of $76,319,516, less the expenditures for New Business Major Projects of $9,371,293; or $66,948,223 divided by the number of New Business services installed during 2022 of 6,870 units.

Q. What are the projected average New Business Program cost per service installed for 2024, 2025, and 2026?

A. The projected New Business Program units and unit costs are provided in Table 5 below. In addition to showing the projected units and unit costs for each calendar year, Table 5 also documents the calculation of the test year dollars for the New Business Program. The projected capital expenditures for November through December of 2025 are 17.6% of the 2025 annual projection, and the projected capital expenditures for January through October of 2026 are 80.6% of the 2026 annual projection.

[9] The 2024 estimate of approximately 49 miles is based on October 2023 through September 2024 actual experience of 48.9 miles (or 258,227 feet).

Table 5: New Business Units and Unit Costs
(in Thousands of Dollars)

Description	Actual 2023	Projected Calendar Year 2024	Projected Calendar Year 2025	Projected Calendar Year 2026	Projected Test Year
Total New Business Dollars (in Thousands; excluding Large New Business projects)	**$66,948**	**$55,332**	**$60,182**	**$63,368**	
Service Installation Units	6,870	6,800	6,800	7,000	
Average Unit Cost (in $)	$9,745.01	$8,137.05	$8,850.26	$9,052.62	
Test Year Dollar Detail:					
Calendar Year amounts included in the Projected Test Year (in Thousands)			**$ 10,586 (November through December)**	**$ 51,096 (January through October)**	**$61,682**

Q. Please explain the difference between the projected unit costs shown above, and the 2023 actual unit cost of $9,745.01.

A. The 2026 projected unit cost of $9,052.62 is less than what would be expected if S&P forecasts of Consumer Price escalation were used to project the 2023 unit cost forward out to 2026. The 2026 projected unit cost in a Consumer Price escalation scenario would be $10,555.67, which is an increase of $1,503.05 per unit, or 16.6% from the Company's 2026 projection.[10]

The 2025 projected unit cost of $8,850.26 is less than what would be expected if S&P forecasts of Consumer Price escalation were used to project the 2023 unit cost forward out to 2025. The 2025 unit cost in a Consumer Price escalation scenario would be

[10] The projected Consumer Price inflation projections for 2024, 2025, and 2026 respectively are 3.2%, 2.4%, and 2.5%. The 2023 actual unit cost of $9,745.01 x 1.032 (2024 Consumer Price Index "CPI" growth) x 1.024 (2025 CPI growth) x 1.025 (2026 CPI growth) = 10,555.67. Alternatively, the average of the 2024, 2025, and 2026 Consumer Price inflation projections is 2.7%; therefore, the calculated 2026 unit cost estimate based on the average inflation projection would be $9,745.01 x 1.027 x 1.027 x 1.027 = $10,555.86. The CPI growth rates used in this calculation are documented in WP-HLR-33.

$10,298.22,[11] which is an increase of $1,447.96 per unit, or 16.4% from the Company's 2024 projection.

The 2025 projected unit cost of $8,850.26 is equivalent to decreasing the 2023 actual average unit cost at 4.7% per year.[12] The 2025 projected unit cost are lower than the 2023 actual amount due to constraints on the Company's total forecasted dollars for the New Business Program based on the direct testimony of MPSC Staff ("Staff") witness Cynthia L. Creisher in Case No. U-21490, which estimated test year ending September 30, 2025 New Business Program capital expenditures of $63.2 million.[13]

The 2024 projected unit cost of $8,137.05 is less than what would be expected based on S&P forecasts of Consumer Price escalation were used to project the 2023 unit cost forward to 2024. The 2024 projected unit cost in an updated Consumer Price escalation scenario would be $10,056.85, which is an increase of $1,919.80 per unit, or 23.6% from the Company's 2024 projection.

The 2024 projected unit cost of $8,137.05 is 16.5% less than the 2023 actual unit cost. This projection includes eight months of actual expenditures and four months of projected expenditures and reflects decreases in various contractor costs that are being realized during 2024.

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[11] 2023 actual unit cost of $9,745.01 x 1.032 (2024 CPI growth) x 1.024 (2025 CPI growth) = $10,298.22. The CPI growth rates used in this calculation are documented in WP-HLR-33.

[12] 2023 actual unit cost of $9,745.01 x 0.95299 x 0.95299 = 8,850.26.

[13] Case No. U-21490, Direct Testimony of Staff witness Creisher, page 16, line 6. Please note that $3.2 million has been allocated to Large New Business for three specific projects during 2025, and the Large New Business dollars are excluded from the calculation of the 2025 projected unit cost.

Q. Please describe the process of connecting customers under the New Business Program.

A. When the Company receives a request for a new connection, the Company documents the customer's location, requested load, and required delivery pressure. The Company's engineering staff then analyzes the existing system to determine the necessary steps to provide gas service to that customer. In each of these cases, the customer will be responsible for the cost of work required to make the connection, including main installation, service installation, permit costs, etc. The determination of the amount of contribution required from each customer, however, will consider projected revenue from the customer, according to the Customer Attachment tariffs, as stated in Rule C8 of the Company's Rate Book for Natural Gas Service (the Company's "Tariff").

Q. What is the status of the Company's CAP sub-program?

A. In 2019, the Company completed the last proactively marketed CAP main installations. The program continues to exist to track the service installations connected to the CAP mains until the associated CAP charges expire, which is 10 years from the date of installation. All new requests that require gas main extensions will continue to be processed according to the Company's Tariff relating to Customer Attachment, as stated in Rule C8 of the Company's Tariff, but the Company is not proactively soliciting to scope and construct additional CAP main extensions. New service connections to existing CAP mains are available with the prorated monthly payment option until expiration of the CAP charges on that system. The actual costs incurred during 2023 are detailed on line 3, column (b) of Exhibit A-101 (LDW-2). Actual CAP program service installation costs incurred during 2024 are included as part of "Mains Services & Meter Stands – Dist" on line 1, column (c) of Exhibit A-101 (LDW-2).

Q. Please describe the projects in the Large New Business sub-program, represented on Exhibit A-101 (LDW-2), line 2.

A. The Large New Business sub-program includes new customer connection projects where the estimated infrastructure cost exceeds $500,000, the Company plans to enter a facilities agreement for unpredictable operations, or the Company deems it necessary for special tracking and project management and, therefore, included it in a separate sub-program. Projects are generally created under this sub-program when the requesting customer has signed a contract with the Company locking in the load requirements and revenue expectations. As with the New Business Mains and Services sub-program, Company Tariff Rule C8, relating to the Customer Attachment Program, is utilized to determine the Customer's contribution to the total project cost. Large New Business projects that have been constructed during 2023 include a 4.0 mile extension of 4" high pressure steel main to provide natural gas service to a new renewable natural gas facility near Saranac, and a 1.8 mile extension of 8" high pressure steel main to provide natural gas service to a new battery manufacturing facility in Lansing. During 2024 and 2025, the Company is constructing a 1 mile extension of 8" high pressure steel main to serve a battery manufacturing facility in Marshall and an approximately 4,500 foot extension of 6" high pressure steel main in Hemlock to serve a new plant that manufactures components for the solar power industry. The Company is also planning to construct an approximately 200 foot extension of 8" high pressure steel service to serve a natural gas fired electric generation facility expansion in the Lansing area and a 1400 foot extension of 6" high pressure steel main to serve an industrial site redevelopment in Flint. Currently, there are no specific new projects included in the projections for this sub-program for 2026. New requests for load, however, can be received at any time, meaning the Company may add projects to this program as customer requests materialize. The Company's capital expenditure projection for the test year ending October 31, 2026 includes $4.78 million for unspecified future project capital investments in the Large New Business sub-program.[14] Historically, the Company has invested $67.3 million since 2019 to construct gas service facilities for large customers.[15]

Gas service facilities that have been installed as required to meet customer service requirements include high-pressure gas mains, city gate and regulating station equipment, services, and meter stands. Site restoration costs for these projects are also included in this sub-program. The projects identified in Table 6 below are examples of the Company's efforts to support economic development efforts within Michigan.

[14] The 2026 calendar year projection is $5.07 million, the test year includes the portion expected to be incurred during January through October of 2026.

[15] The historical period referred to in this statement includes January 2019 through September 2024.

Table 6: Large New Business Capital Expenditures – History (in thousands of dollars)

Program Description	Historical 2019	Historical 2020	Historical 2021	Historical 2022	Historical 2023	2024 January through September
Lansing BW&L Delta Energy Park Project	11,160	20,519	1,499	675	-46	
Agriculture Processing Complex Project	10,759	6,256	193	28	166	
Industrial Expansion Project		5,064	766	9		
RNG Facility				4	4,377	-1
Battery Manufacturing Facilities				67	4,875	2,847
Other Large New Business Projects	-4,005	1,601	-51	65		484
Total Capital	**17,914**	**33,440**	**2,406**	**848**	**9,371**	**3,330**

Q. Please explain why the Company is including projections of unspecified Large New Business project capital expenditures in 2026.

A. At the time the Company developed its most recent projections of 2026 capital expenditures, the Company had not received any specific customer requests for main installations in that calendar year. However, the Company's actual experience with recent requests for main installations in 2024 and 2025 is an indicator that it is more likely to receive requests for 2026 construction than to receive no requests at all. Additionally, the Company is also involved in economic development project discussions that have the potential to require construction in 2026. Over the 2019-2023 five-year time period, the Company's average capital investment in Large New Business projects averaged $12.8 million. The Company's 2026 calendar year projection of $5.07 million is approximately 40% of that historical average.

Q. Please conclude your testimony regarding the Company's New Business Program.

A. Based on the evidence provided above, analysis indicates that the Company is prudently planning for New Business Program capital expenditures throughout the bridge period and test year in this proceeding. The Company has reduced the projected volumes of new service installations from Case No. U-21490, and the unit cost projections for the New Business Program are lower than the historical 2023 actual unit cost. The potential exists for cost increases and customer requested main extensions to exceed the Company's forecasts for New Business program investments. Thus, the Company respectfully requests the Commission's agreement with the Company's New Business Program projections as provided in my Exhibit A-101 (LDW-2).

B. <u>Asset Relocation</u>

Q. Please describe the capital expenditures related to the Asset Relocation Program as shown on Exhibit A-12 (LDW-1), Schedule B-5.9, line 2.

A. The Asset Relocation Program includes gas distribution infrastructure replacement projects that are required due to civic improvement activities initiated by federal, state, or local governmental units, or by individual customers with existing gas service. There are two sub-programs within the Asset Relocation Program: Asset Relocation – Civic Improvement and Asset Relocation – Reimbursable. The expenditures for each of these programs are shown in Table 7 below and Exhibit A-102 (LDW-3) provides further details of these expenditures.

Table 7: Asset Relocation Program Capital Expenditures
(in thousands of dollars)

Program Description	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
Asset Relocation – Civic Improvement	83,518	64,148	63,612	127,760	82,162
Asset Relocation - Reimbursable	14,167	22,690	12,226	34,916	16,647
Total Asset Relocation	**97,685**	**86,838**	**75,838**	**162,676**	**98,809**

Asset Relocation – Civic Improvement consists of gas relocation work driven by municipal projects to replace or improve aging public infrastructure such as roadways, bridges, sewer lines, water lines, and drainage ditches. If the Company's existing facilities are in the public road right-of-way by permit, and need to be moved to eliminate interference, this is done at the Company's expense.

Asset Relocation – Reimbursable accounts for customer requested capital replacements. This includes scenarios where the customer has added load requiring facility upgrades, asked for relocation of a gas main or replacement of a gas service to accommodate a customer need, or created an unsafe situation requiring capital replacement. In the case of added load, the project is reimbursable by the customer, with the appropriate future revenue costs applied as outlined in the Company's Tariff Rule C8. Other replacements, without added load, within this category can be fully reimbursed by the customer.

Q. Please further describe the expenditures associated with the Asset Relocation – Civic Improvement sub-program.

A. Asset Relocation – Civic Improvement work was recognized by the MPSC as critical work for gas utilities on page 96, section 4.2.1.6 of the September 11, 2019 Statewide Energy

Assessment Final Report in Case No. U-20464 ("SEA"). Repairing and expanding infrastructure continues to be a significant topic of public interest as well as a priority for state policy. According to the 2023 Report Card for Michigan's Infrastructure, which has been published by the Michigan Section of the American Society of Civil Engineers (or "ASCE"), Michigan is making progress in reversing underinvestment in the state's infrastructure. State and Federal funding sources have included $3.5 billion in bond funding from the "Rebuilding Michigan Program" and $4.7 billion from the "Building Michigan Together" plan. The 2021 Bipartisan Infrastructure Law will also provide $11 billion to address needed infrastructure projects. The ASCE's 2023 Michigan Infrastructure Report Card assessment shows modest improvement in the overall grade from a "D+" in the 2018 report card to a "C-" in the 2023 report card. Roads and stormwater infrastructure grades have improved from a "D-" in 2018 to a "D" in 2023. Civic Improvement Relocation projects frequently involve replacement of vintage mains and services, avoid third party damage to non-vintage facilities, and reduce the potential for leaks when infrastructure contractors are working around vintage main. The annual replacement of vintage mains and services are documented as part of Attachment 9 "Non-EIRP Distribution Main Replacement Project Metrics", which is included in the Company's enhanced infrastructure replacement annual reports.

Q. Please summarize the Company's investments in the Asset Relocation – Civic Improvement sub-program over the past five historical calendar years.

A. Asset Relocation – Civic Improvement sub-program investments by the Company over the 2019 to 2023 historical years have totaled $408.3 million. Over 208 miles of distribution main has been installed and more than 10,700 services have been replaced during the 2019 to 2023 time period.[16] The average annual capital investment has been approximately $81.7 million.

In most cases, the civic improvement projects involve replacement of metallic facilities with plastic pipe. For example, during the 2019 to 2023 period, approximately 90% of the retired gas main associated with civic improvement projects were manufactured from metallic pipeline materials. Historically, the Company has been required to replace portions of high-pressure facilities within this program, which requires the installation of steel pipe. Steel pipe installations represent 9.4% of the civic improvement project main installed during the 2019 to 2023 period. This high-pressure work is more expensive and more time consuming than work on the medium pressure system due to the nature of the material and construction methods required.

Table 8 below summarizes the annual Asset Relocation – Civic Improvement sub-program historical activity for the number of projects completed, the footage of gas main installed, and the number of gas services replaced. This table shows a substantial reduction of civic improvement work completed during 2020 and 2021 relative to prior historical experience.

[16] Distribution miles installed and services replaced are reported annually as part of the Company's Gas Enhanced Infrastructure Replacement ("EIRP") Annual Report. Asset Relocation – Civic Improvement projects are included in Attachment 9 of those annual reports.

Table 8: Asset Relocation – Civic Improvement Project History[17]

	2019	2020	2021	2022	2023	5-Year Average
Projects completed	202	124	152	170	122	**154**
Feet of Distribution Main Installed	254,605	169,202	195,305	297,246	181,953	**219,662**
Services Replaced	2,924	1,729	2,377	2,494	1,228	**2,494**

Table 9 identifies specific examples of large Asset Relocation – Civic Improvement projects that have required investments of more than $3 million by the Company over the 2017 through 2023[18] time period. The actual values during 2022 and 2023 reflect large capital expenditure requirements associated with the Mound Road reconstruction project, which is expected to be complete by the end of 2024.[19] Another large civic improvement project is the Iron Belle Trail, which provides bicycling and hiking opportunities on trails that extend more than 2,000 miles from the western tip of Michigan's Upper Peninsula to Belle Isle in Detroit. It has been recently reported that the Iron Belle Trail is 71% complete.[20] In addition, the City of Eastpointe's 9 Mile Road reconstruction and water infrastructure project is planned to occur between 2023 and 2025 and will include the addition of green space, benches, bike paths, and other enhancements that will make 9 Mile Road more pedestrian and bicycle friendly.[21]

[17] Source: Attachment 9 to Gas EIRP Annual Report.

[18] The 2023 amount includes actual capital expenditures for January 2023 through September 2023.

[19] https://www.detroitnews.com/story/news/local/macomb-county/2022/09/15/project-rebuild-mound-road-nearly-40-complete/10386613002/, accessed 11/22/2024.

[20] https://www.michigan.gov/dnr/places/state-trails/iron-belle, accessed 11/22/2024.

[21] https://www.macombdaily.com/2023/03/05/modern-9-plan-encompasses-more-than-road-repaving/, accessed 11/22/2024.

Table 9: Asset Relocation – Civic Improvement Large Project History (in Thousands of Dollars)

	Project Reference	2017	2018	2019	2020	2021	2022	2023	2024 January - September
I-75 & M-46 Reconstruction	16161				$8,994	$76	$39		
M-59 Tipsico Lk to Milford Rd	13821	$4,204	$2,209	$1,876		-$75			
I-75 Segment 3	17080			$2,215	$3,836				
M-24 Phase 2	17113			$2,525	$1,657	$1	-$5		
Marion Ave	18972					$3,755	$146	$55	-$8
Oakland Drive	17037				$3,879	($1)	$39	$49	
Mound Rd 13 to 14 Mile	19952						$5,129	$282	
Mound Rd 11 to 13 Mile	20136						$1,491	$9,037	
Atherton Road	16461			$709	$2,762	$5	-$34		
M-59 Lakena to Tipsico Lake	14579		$3,456	($45)					
I-75 Projects	GL-02841 GL-02842				$1,069	$3,884	$61		
Iron Belle Trail/ Gale Rd.	11001	$3,253							
13 Mile Road and Inkster	10010		$3,238						
I-94 BR Mich Ave	16055			$3,015					
Shiawassee & MLK	19927						$5,530	$707	$125
Lapeer Rd Burton	20993						$3,848	$153	$2
Passolt St	19624						$4,996	$79	
Atlas Iron Belle Trail	19919						$56	$7,910	$41
US 127 & 223	20824							$3,178	
Wayne Rd Bridge Replacement	20855						$303	$2,669	
9 Mile Road Eastpointe	19765 21012 22727					$4	$92	$10,623	$6,393
Other Projects	Various	$50,779	$59,514	$80,406	$53,524	$49,316	$81,375	$48,776	$37,048
Total Asset Relocation - Civic		**$58,236**	**$68,417**	**$90,700**	**$74,653**	**$56,401**	**$103,075**	**$83,518**	**$43,601**

Q. Please summarize the Company's projected investments in the Asset Relocation – Civic Improvement sub-program.

A. Asset Relocation – Civic Improvement sub-program expenditure projections are developed by engineering staff within the Gas Engineering Asset Planning Department and are summarized in Table 10 below. The scope and location of individual projects will be determined as requests are received. The projected test year amount of $82,162 reflects the Company's expectation that 10.11% of the 2025 calendar year capital investments and 89.88% of the 2026 calendar year capital investments will occur during the November 2025 to October 2026 time period.

Table 10: Asset Relocation – Civic Improvement Projections (in Thousands of Dollars)

Description	Actual 2023	Projected Calendar Year 2024	Projected Calendar Year 2025	Projected Calendar Year 2026	Projected Test Year
Total Asset Relocation – Civic Improvement (Thousands of Dollars)	**$83,518**	**$64,148**	**$70,770**	**$83,444**	
Test Year Dollar Detail:					
Calendar Year amounts included in the Projected Test Year (in Thousands)			**$7,158 (November through December)**	**$75,003 (January through October)**	**$82,162**

The calendar year 2026 projection of $83.444 million is a decrease of $0.074 million, or approximately 0.1% less, compared to the 2023 actual capital expenditures. Table 11 indicates the Company expects to install 166,365 feet of distribution main during 2026, which is an approximately 8.6% decrease in workload compared to 2023. Therefore, the difference between the calendar year 2026 capital investment and the 2023 historical actual capital investment is due to decreases in projected work offset by increases in the average cost per mile installed of approximately 3% annually.

The calendar year 2025 projection of $70.770 million is a decrease of $12.748 million, or approximately 15.3% less, compared to 2023. Table 11 indicates that the Company expects to install 145,330 feet of distribution main during 2025, which is an approximately 20% decrease in workload compared to 2023. The difference between the calendar year 2025 capital investment and the 2023 capital investment, therefore, is due to decreases in projected work offset by increases in the average cost per mile installed of approximately 3% annually.

The calendar year 2024 projection of $64.148 million is a decrease of $19.370 million, or approximately 23.2% from 2023. Table 11 indicates that the Company expects to install 126,637 feet of distribution main during 2024, which is an approximately 30.4% decrease in workload. Therefore, the difference between the calendar year 2024 capital investment and the 2023 capital investment is due to decreases in projected work, offset by somewhat higher unit costs. In Table 9, I have identified actual capital expenditures through September 2024 of $43.601 million.

Q. Please summarize the work that the Company expects to complete during the 2024 through 2026 calendar years within the Asset Relocation – Civic Improvement sub-program.

A. Projected work for the Asset Relocation – Civic Improvement sub-program is detailed in Table 11 below. Specific projects that the Company has included in its 2023 actual and future year projections include the Mound Road reconstruction project, the Atlas Iron Belle Trail project, the 9 Mile Road Eastpoint project, and the Romeo Plank project.

Table 11: Asset Relocation – Civic Improvement Projection Details

	Actual 2023	**2024 (Projected)**	**2025 (Projected)**	**2026 (Projected)**
Projects	122	171	176	181
Feet of Distribution Main to be Installed	181,953	126,637	145,330	166,365
Asset Relocation Services to be Replaced	1,228	1,640	1,689	1,740

Q. What benefits are realized from the Company's investments in the Asset Relocation – Civic Improvement sub-program?

A. There are significant benefits realized because of capital investments in this program from an asset integrity and public safety perspective. Replacing vintage gas mains and services in the vicinity of heavy construction equipment reduces the likelihood of a leak either during or after construction that could result from the ground impact of that construction. This enhances the safety of those working on public infrastructure projects near these facilities, as well as any members of the general public that utilize the associated infrastructure. The coordination between the Company and the municipalities allows for the Company to have an increased awareness and better communication with the excavators on the project to prevent damages to the Company's gas system. Additionally, the relocation of mains and services can enable the future maintenance of main and service lines while minimizing disturbances to completed roadway improvements.

Q. How does the Company coordinate with road right-of-way owner agencies when it comes to public infrastructure improvement projects?

A. The Company is a strong proponent of coordinating infrastructure projects among utilities and road right-of-way owner agencies. Many of these public infrastructure projects affect the Company's gas distribution facilities. In support of the Company's continual effort to promote coordination and efficient civic improvement projects, the Company also continues to be involved in the Michigan Infrastructure Council. The Company has engineering staff representatives that serve on subcommittees and contribute to periodic council meetings. Additionally, the Company encourages engineering staff to attend the Asset Management training sponsored by the Michigan Infrastructure Council.

The Company's Gas Engineering Asset Planning Department works with state and local government agencies to replace vintage gas facilities when appropriate for safety and reliability, and to attempt to save newer gas main and service materials from having to be replaced to minimize expense to the Company. Cities may have large programs to replace sewer systems or water main replacements, requiring major road construction and deep sewer or water installation. The Company will coordinate timing with the city to replace vintage mains and services that may leak from such type of construction. Coordinating project timelines with municipalities to align construction schedules also allows the Company to reduce its costs for hard and soft surface restoration once the gas system work is complete.

Additionally, there are many projects where the Company has plastic or coated and wrapped steel facilities, primarily gas mains, near the construction activities and will negotiate with the municipality or their engineering firm to get designs changed to protect the Company's gas facilities and prevent relocation. The Engineering Asset Planning team reviews municipal project plans and tries to negotiate municipal design changes to eliminate potential direct conflicts with Company facilities. These negotiations reduce overall project scope and, therefore, reduce the costs to both the taxpayer and the Company's customers.

Q. Please summarize the Company's projections for the Asset Relocation – Civic Improvement sub-program.

A. As shown on Exhibit A-102 (LDW-3), line 1, the capital expenditures for the Asset Relocation – Civic Improvement Program were $83,518,139 in 2023, and are projected to be:

- $64,148,130 for the calendar year 2024;
- $63,611,817 for the ten months ending October 31, 2025; and
- $82,161,630 for the test year ending October 31, 2026.

These projections are based upon recent history, projections of increased federal and state funding for infrastructure improvements, and knowledge of specific projects planned for the next several years. The Company's projected capital expenditure amounts are required to meet the projected level of asset relocations associated with local and state government projects.

Q. Please further describe the expenditures associated with the Asset Relocation – Reimbursable Program.

A. The Asset Relocation – Reimbursable Program accounts for customer requested capital replacements of mains, services, and meter stands. These replacements are requested for multiple reasons, including when the customer desires to add sufficient gas equipment such that it requires a Company facility upgrade, has asked for relocation of a gas main or replacement of a gas service to accommodate a customer need, or has created an unsafe situation requiring Company facility replacement. Customers requesting or requiring these upgrades are responsible for the cost of the upgrade. When a customer is adding gas load that will provide the Company more revenue, the Company applies the appropriate revenue credits as outlined in Tariff Rule C8 to help offset the customer's costs.

Q. What has been the Company's historical experience with the Asset Relocation – Reimbursable Program?

A. The Asset Relocation - Reimbursable Program investments have totaled $59.6 million for approximately 25,500 orders from 2019 through 2023, for a historical five-year average capital investment of approximately $11.9 million annually. During 2024, the Company invested approximately $19.0 million for more than 6,340 orders during the first nine months of the year and is projecting a total 2024 investment of $22.7 million because of increasing requests for relocation work being experienced by the Company during 2024. The $22.7 million projected for 2024 exceeds the $11.9 million of annual average investment experienced by the Company during 2019 through 2023. The increase of capital expenditures in 2024 is primarily related to a large project enabling the conversion of an existing vehicle assembly plant to shift production to electric vehicles, as well as increasing expenditures related to customer requests for meter stand replacements.

Table 12: Asset Relocation – Reimbursable sub-program Details (in Thousands of Dollars)

	2019	2020	2021	2022	2023	2024 (Jan - Sep)
Customer Requested Relocations	$9,338	$7,260	$5,888	$11,526	$12,956	$9,969
Damage Replacements	$1,570	$1,685	$1,473	$1,898	$1,100	$933
Large Customer Requested Relocation Projects	$4,755	$11			$107	$8,119
Other		$364	-$386	$4	$5	
Total Asset Relocation – Reimbursable	**$15,663**	**$9,320**	**$6,975**	**$13,429**	**$14,167**	**$19,020**

The 2023 actual costs and future period projections for this sub-program are reflected on Exhibit A-102 (LDW-3), line 2, and summarized as part of the Asset Relocation Program in Table 7 above. The capital expenditures for this sub-program were $14,167,169 in 2023 and were $738,603 higher than 2022 capital expenditures for this sub-program.

Q. Why are the 2023 actual amounts for the Asset Relocation – Reimbursable sub-program higher than the 2022 actual amounts?

A. The 2023 actual amount is higher than 2022 due to the following reasons:

- Customer Requested Relocation work required $1.429 million more investment due to increased costs associated with customer requests for meter stand work in 2023; and
- Damage Replacement work required $0.798 million less investment due to lower main replacement work order costs in 2023.

Q. Please describe how the forecasts for the Asset Relocation – Reimbursable sub-program were developed.

A. The Company's Customer Energy Management Department manages the Asset Relocation – Reimbursable sub-program and provides the forecasts for future year capital investments. The test year forecast of $16,647,126 includes $2,830,429 for November and December 2025 and $13,816,697 for January through October 2026. 81.2% of the 2026 annual forecast of $17,015,323 and 18.8% of the 2025 annual forecast of $15,056,675 are expected to occur in the test year based on historical timing of expenditures within this sub-program.

The 2026 calendar year forecast of $17,015,323 includes projected customer requested relocation investments of $15,474,782 and investments to correct damages of

$1,540,540. The increase in 2026 compared to the 2023 calendar year actual amount anticipates cost escalation and increasing requests for customer requested relocation work.

The 2025 calendar year forecast of $15,056,675 includes projected customer requested relocation investments of $13,594,649 and investments to correct damages of $1,462,026. The 2025 forecast anticipates cost escalation and increasing requests for customer requested relocation work from the 2023 actual amount.

The 2024 calendar year forecast of $22,690,010 includes actual investments for the first eight months of 2024 in the amount of $17,220,105 and projected investments for the last four months of 2024 in the amount of $5,469,905. The 2024 calendar year forecast is $8,522,841 more than the 2023 historical year amount. As noted previously, this increase is primarily related to customer requested relocation work at a large vehicle assembly facility as well as increasing customer requests for meter stand replacements.

Q. Please summarize the Company's projections for the Asset Relocation – Reimbursable sub-program.

A. As shown on Exhibit A-102 (LDW-3), line 2, the capital expenditures for the Asset Relocation – Reimbursable sub-program were $14,167,169 in 2023, and are projected to be:

- $22,690,010 for the calendar year 2024;
- $12,226,246 for the ten months ending October 31, 2025; and
- $16,647,126 for the test year ending October 31, 2026.

The Asset Relocation – Reimbursable sub-program projections are based upon the Company's recent experience with this sub-program. The Company's projected capital expenditure amounts are required to complete work associated with customer requested asset relocations and to resolve gas facility damages.

C. Regulatory Compliance

Q. Please describe the capital expenditures relating to the Regulatory Compliance Program shown on Exhibit A-12 (LDW-1), Schedule B-5.9, line 3.

A. The Regulatory Compliance Program includes projects that are required to comply with federal and state pipeline safety regulations and mandates. For gas distribution, components of this program are the Regulatory Base Distribution projects, the Meters sub-program, MAOP Distribution projects, and Cathodic Protection Distribution projects. The capital expenditures for this program were $34,487,525 in 2023, and are projected to be $45,216,771; $91,703,502; and $150,311,390 for the years 2024; the ten months ending October 31, 2025; and the test year ending October 31, 2026, as set forth on this exhibit on line 3, column (b); line 3, column (c); line 3, column (d); and line 3, column (f), respectively, of Exhibit A-12 (LDW-1), Schedule B-5.9. A further breakdown of the Regulatory Compliance Program expenditures is shown on Exhibit A-103 (LDW-4). The Regulatory Compliance expenditures are also shown in Table 13 below.

Table 13: Regulatory Compliance Program Capital Expenditures (in thousands of dollars)

Program Description	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
Regulatory Base - Distribution	$39	$0	$0	$0	$0
Meters	$20,450	$24,909	$23,457	$48,366	$24,700
MAOP Distribution	$1,607	$9,295	$59,964	$69,259	$115,812
Cathodic - Distribution	$12,392	$11,013	$8,282	$19,296	$9,800
Total Regulatory Compliance	**$34,488**	**$45,217**	**$91,704**	**$136,920**	**$150,311**

Q. Please describe the Regulatory Base Distribution sub-program.

A. This sub-program includes the capital construction projects that were required to meet regulatory commitments. This five-year program began in 2017 with an initial plan for 17 projects. When the Company committed to this program, it also committed to continue to monitor the Supervisory Control and Data Acquisition ("SCADA") system for station pressures that exceed 18" water column of pressure on each station outlet and address those as well. Through that continued observation, one of the original projects, High Street in Charlotte, was cancelled after further system planning analysis allowed the Company to lower the station pressure without any replacement. Another project, First Street in Jackson, was eliminated as the Company was able to coordinate the necessary system configuration changes with an Asset Relocation – Civic Improvement project for the City of Jackson in 2018. One project, Ada Street in Owosso, was added due to observed station pressures, bringing the total back to 17 projects in the program. The Chipman Street project in Owosso was split into two phases to allow it to be constructed over two years; a railroad crossing was completed in 2018 and the remainder of the project was completed in 2019.

These projects replaced sections of the standard pressure system with medium pressure plastic, which removed load from the standard pressure system. Standard pressure, sometimes called utilization pressure, is a low-pressure distribution system typically operating at 14" water column (~0.5 psig) or less where there may or may not be regulating equipment at the customer's meter, meaning the pressure on the system is the pressure that is provided to the customer. Medium pressure systems operate between 1 psig and 60 psig, meaning that each customer has a regulator installed at their meter to reduce the pressure prior to customer's end-use equipment. The scope of work for a typical project involved replacing all vintage mains and services along with any other facilities not rated for the medium pressure system. Any existing main and service facilities rated to operate at medium pressure, but still operating at standard pressure, would be converted to medium pressure without replacement. Customers on both the replaced or upgraded sections of the system were provided with an appropriate meter and regulator to reduce the pressure before it enters the customer's building. Together, these changes to the system allow the Company to convert sections of the standard pressure system to medium pressure while reducing the operating pressures of the remaining standard pressure systems from 18" water column to 14" water column or less. These changes were agreed to by the Company and the MPSC Safety Staff in 2017. The Company completed this five-year program in 2022, as shown in Table 14 below:

Table 14: Regulatory Base Distribution sub-program Compliance Project List with Status

Project Number	Headquarters	Project Name	Construction Year
11804	Jackson	Michigan	2018 – Complete
11693	Flint	South Flint SP	2018 – Complete
11979	Flint	Downtown SP	2018 – Complete
11747	Jackson	Ganson	2018 – Complete
12065	Bay City	Bay City East SP, Lincoln St.	2018 – Complete
11908	Owosso	Chipman	2018 – Complete
16175	Owosso	Chipman - Ph II (a.k.a. Cedar St.)	2019 - Complete
11716	Jackson	Seymour	2020 – Complete
11690	Flint	West Flint SP	2019 – Complete
11689	Flint	East Flint SP	2019 – Complete
14024	Jackson	Foote	2020 – Complete
11807	Jackson	Morrell	2019 – Complete
14016	Jackson	First St SP	2019 – Cancelled
11719	Bay City	Bay City West SP Walnut Street	2020 – Complete
12057	Bay City	Bay City East SP, Water Street	2021 - Complete

11720	Bay City	Bay City West SP Vermont Street	2021 - Complete
11717	Saginaw	Saginaw East SP	2022 – Complete
16132	Owosso	Ada St	2021 – Complete
12085	Lansing	High St – Charlotte	Cancelled

While this program reduces the operating pressure on the standard pressure system, there are additional benefits from this work. The projects constructed within this sub-program replaced approximately 10 miles of cast iron and other vintage mains and eliminated more than 200 vintage services. Existing plastic main in the standard pressure system was converted or uprated to medium pressure wherever practical, reducing the cost of replacement for these segments, while still transitioning them from the standard pressure system.

The Regulatory Base Distribution compliance sub-program is complete. The above details are included in my testimony to describe capital investments made during the historical year of 2022. The 2022 expenditures detailed on Exhibit A-103 (LDW-4), line 1, include actual capital investments made to complete the Company's standard pressure system upgrade commitment.

Q. Please describe the Meters sub-program within the Regulatory Compliance Program and the projections in this filing.

A. The meters purchased in the Regulatory Compliance Program are used in connecting New Business Program services, the Routine Meter Exchange Program, the Vintage Service Replacement Program, and for normal replacement of obsolete or broken meters. The Routine Meter Exchange Program involves replacing a portion of existing meters that measure customer consumption with a new or refurbished meter, then testing the old meter for compliance with MPSC billing accuracy standards. The Meters Program also includes equipment purchased for customer requested work such as new service or meter requests, meter exchanges, and sets at existing premises where the meter had been previously removed. The meters being purchased are rotary meters and temperature compensating meters.

The Company purchases new gas meters on a periodic basis to ensure it has an adequate supply to meet customer and regulatory commitments. The Company establishes an annual meter purchase plan for each year in June of the preceding year. That purchase plan provides for meter quantities and types, broken into periodic releases from meter manufacturers throughout the year to meet all business requirements. Those requirements include new business sets, service upgrades, for-cause exchanges (damage, leak, obsolescence, etc.), project work such as EIRP and Vintage Service Replacements ("VSRs"), and regulatory testing requirements. Factors considered when establishing the annual plan include examination of current levels of inventory by meter type, assumptions of new business services expected in the coming year, historical for-cause exchange data, project work projections, historical trends for meter retirements, and regulatory program (i.e., the Routine Meter Exchange Program) projections. The meters are purchased according to that annual plan. The plan calls for receiving shipments of meters at different points throughout the year, so the Company can adjust the orders as material usage variations are observed. The projected test year dollar value includes 11.95% of the 2025 calendar year projection and 88.05% of the 2026 calendar year projection based on historical timing of meter purchase investments. The actual and projected total number of meters purchased for the Meters Program for each period in this filing are shown in Table 15 below:

Table 15: Actual and Projected Meters Program Purchases by Year

	2023 Actual	2024 Projection	2025 Projection	2026 Projection	Projected Test Year
Meter Units	35,200	43,107	47,546	46,394	46,574
Unit Cost	581	578	560	527	530
Total Meter Cost	**$20,450,366**	**$24,909,000**	**$26,641,190**	**$24,436,055**	**$24,699,612**

Q. What have the historical purchases and unit costs been for the Meters sub-program?

A. Historical purchases and unit costs are presented in the table below:

Table 16: Historical Actual Meters Purchased by Year

	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual
Meter Units	67,023	58,997	49,759	21,152	35,200
Unit Cost	435	419	503	546	581
Total Meter Cost	**$29,132,703**	**$24,742,799**	**$25,022,976**	**$11,558,636**	**$20,450,366**
Correctors	1,135	1,460	3,832		
Unit Cost	1,316	1,383	1,331		
Total Corrector Cost	**$1,493,119**	**$2,018,812**	**$5,100,820**		
Comm Modules	3,762	200	100		
Unit Cost	227	131	207		
Total Comm Module Cost	**$854,519**	**$26,166**	**$20,667**		
Total sub-program	**$31,480,341**	**$26,787,777**	**$30,144,463**	**$11,558,636**	**$20,450,366**

Q. What changes have impacted the costs of the Meters sub-program?

A. The costs in the Meters sub-program have been impacted by four significant changes in the recent past, all of which have affected unit cost for the meters purchased.

First, with the conclusion of the Advanced Meter Infrastructure ("AMI") and Automated Meter Reading ("AMR") programs in 2019, all meters are purchased with a gas communication module ("GCM") installed on the meter by the meter manufacturers. While the AMI and AMR programs were being implemented, the initial purchases of GCM devices were within the scope of those programs. With the initial installation of AMI and

AMR now complete, the cost of module purchases are included as part of the Meters Program. GCMs are meter manufacturer and meter-type specific. When meters are returned from the field, if the meter is scrapped or retired, the GCM is either scrapped or retired or, in the case of meters that will be returned to service, some GCM units are recycled to be used as replacements for defective or damaged GCMs or to mitigate any supply chain disruptions on the part of the GCM manufacturer that would cause delays in new meter shipments from the meter manufacturers. The Company has utilized recycled GCMs on new meters when the GCM supplier was unable to deliver GCMs to the meter manufacturer for installation before shipping new meters to the Company. The recycling of GCM units limits the purchase of new stand-alone GCMs primarily to the meter units that come with the GCM already installed.

Second, in late 2020, the sole-source provider of regulated meters (meters with a built-in regulator) announced the decision to discontinue production of diaphragm gas meters in mid-2021. From 2021 forward, the primary meter purchased will be the temperature compensating meter. The temperature compensating meter requires a separate regulator to be installed as part of the meter stand equipment. Purchasing meters without a built-in regulator will lower the unit cost of meters purchased within this program. The cost of the in-stand regulator is not included in this program but is included in work orders as part of other O&M expense and capital expenditure programs.

Third, historically, gas meter volume and temperature correctors and GCMs purchased as stand-alone units were purchased in this sub-program. Those stand-alone units are now included in the Meter Technology and Management Systems Support Program, which is sponsored by Company witness James P. Pnacek. The removal of these future purchases is reflected in Table 15, above. All new meter purchases include the meter, the GCM, and where required, the temperature and volume correctors as a single unit.

The fourth and final item affecting expenditures in the Meters Program is testing equipment. In addition to meter purchases, this program contains costs for the testing equipment at the Company's Meter Technology Center. In 2020, the Company had planned to procure new leak test equipment for the regulated meters. With the end-of-life decision for the regulated meters, and the shift to the temperature compensating meters, the decision was made to shift the purchase of leak test equipment to temperature compensating meter leak testers and the procurement of that equipment was completed in 2022. In 2022, the Company procured new commercial and industrial test equipment and plans to acquire regulator test equipment over the next few years. Additionally, the 2022 expenditures in this sub-program include three new leak testers to support testing of unregulated meters. Meter test stations are also periodically replaced as needed within the expenditures for this sub-program. In 2025, the Company will be replacing regulator test equipment and temperature and pressure instrument test equipment.

Q. Please describe the MAOP Distribution sub-program within the Regulatory Compliance Program and the projections included in this filing.

A. The MAOP Distribution sub-program includes expenditures for projects on the gas distribution system where reconfirmation of the established MAOP is required due to new gas code language included in Pipeline and Hazardous Materials Safety Administration's

("PHMSA") regulation 49 CFR 192.624.[22] The PHMSA code states that pipeline segments that operate above 20% of the specified material yield strength (or "SMYS") are classified by PHMSA as transmission pipelines for the purpose of compliance with safety standards including MAOP. This regulation requires the Company to have a plan to reconfirm MAOP and remediate line segments for which the Company's pressure test records do not meet PHMSA's expectations for traceable, verifiable, and complete documentation. The compliance milestones set forth by the regulation are to complete all actions required by 49 CFR 192.624 on 50% of the pipeline mileage subject to MAOP reconfirmation requirements by July 3, 2028, and complete all actions required by 49 CFR 192.624 on 100% of the pipeline mileage subject to MAOP reconfirmation requirements by July 2, 2035. In some specific cases, replacement of gas distribution assets is determined to be the most effective way of reconfirming the MAOP. The Company has identified thirty-one projects to date, representing approximately 40.25 miles of distribution main installation, and these projects are listed in Appendix F of the NGDP exhibit sponsored by Company witness Dreisig. Projections for each project included in this sub-program are developed by the Company's Engineering Asset Planning Department. Fourteen projects will have capital expenditures during 2023 through 2026 as shown in Table 17 below:

[22] 49 CFR 192.624 is titled "Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines"; Michigan Administrative Code R 460.20606 adopts 49 CFR Part 192 by reference.

Table 17: MAOP Distribution sub-program Compliance Project List

Project Number	Project Name	2023 Projected ($000)	2024 Projected ($000)	2025 Projected ($000)	2026 Projected ($000)	Construction Completion Year
21948 & 21250	Line 1080, West from Kalamazoo	363	3,829	30,041	465	2025
22861 & 22862	Line 1022, Airport CG to State Rd & State Rd to W Grand River	41	87		39,781	2026
22781	Line 1041, Lapeer Rd	244	306			2028
22393	Line 1002c	934	688	15,428	40,063	2029
21676	Line 1093, Shattuck Rd				20,901	2026
21788	Line 1009, Huron Park to I-94	24	3,183			2024
22511	Line 1022f, Vermontville			373		2025
22157 & 22494	Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile; 9 Mile to 10 Mile			19,935	9,643	2025 2026
22702	Line 1006, Groebel Dr to Mound Rd		161		6,215	2026
22150	Line 1002f, Macomb ITC Corridor		16	2,980		2025
22409	Line 1020, Greenfield Rd		258			2024
21674 & 21675	Line 1087b, East and West Segments		505	10,173		2025
TBD	Line 1026f, Mt Hope				10,829	2026
TBD	Line 1026i, MSU PP					2027
22532	Line 1090n, Davis St		218	109		2025
	Program Adjustment		44	-9,923		
Total 2023-2026 Projection		**$1,607**	**$9,295**	**$69,117**	**$127,897**	

Q. Please explain why the replacement of gas distribution assets would be determined to be the most effective way of reconfirming the MAOP of a line segment.

A. For the projects requiring reconfirmation, engineering staff within the Company have performed an evaluation to determine the best course of action to comply with 49 CFR 192.624. The Company must utilize one of six methods identified in 49 CFR 192.624 to reconfirm its MAOP. The Company selected reconfirmation Method 4 - Pipeline Replacement as the preferred approach for remediation after evaluating all the methods offered in 49 CFR 192.624 for each gap segment. In general, the Company arrived at this conclusion because the other reconfirmation methods are not practical or feasible due to existing operational constraints and risks on the Company's distribution system. One benefit of pipeline replacement is that the replacement pipeline would be designed, constructed, and pressure tested according to current standards to establish MAOP. Pressure testing would take place on the new pipe prior to being placed into service. As a result, operational risks and constraints associated with re-testing pipe that is already in-service would be avoided.

The other identified methods were not selected for several reasons. For example, reconfirmation Method 1 – Pressure Testing, is an infeasible option in cases where operational constraints and risks surrounding gas quality and gas deliverability requirements exist. This is infeasible because the natural gas distribution system is not generally designed for the removal of water from the pipeline after completion of pressure testing and material verification procedures required to comply with the traceable, verifiable, and complete documentation standard; this means many distribution line segments may only be resolved through pipeline replacement. Additionally, reconfirmation Methods 2 and 5, which relate to pressure reductions, are generally not practical solutions in most instances because the Company cannot meet gas deliverability[23] requirements at the reduced MAOP to comply with the regulations.

All three of these methods are examples of situations that create an unacceptable risk. For instance, if pressure testing failed, the line would have to be replaced anyway and the potential for unplanned outages during such an event, particularly if it created the need for replacement before the winter heating season, would create a risk that the Company would not be able to provide gas to customers when needed. Similarly, the line segments identified as requiring MAOP confirmation exist on critical high-pressure systems, some being highly interconnected; this is especially true for distribution lines in the southeast Michigan portion of the Company's service area. In each instance, a pressure reduction would have to be taken along the full length of the line – or multiple adjacent lines in the case of interconnected systems – which would reduce deliverability in downstream line segments.

Q. Please explain the Line 1080 project.

A. In addition to the work being done by the Company to evaluate compliance with MAOP standards described above, the Company has received notice from Staff that Line 1080, which serves customers to the west of Kalamazoo, needs to be operated at a lower pressure to comply with 49 CFR 192.619.[24] The Company, however, cannot meet current deliverability requirements at this new specified operating pressure. Options to augment

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[23] Definition of gas "deliverability": the ability of a natural gas service provider to meet its customers' needs based on seasonal requirements and operating conditions.

[24] 49 CFR 192.619 is titled "Maximum allowable operating pressure: Steel or plastic pipelines"

this line segment have been reviewed by the Company, and pipeline modifications are planned for construction during 2025.

The Line 1080 project is unique among the MAOP projects planned for during the timeframe of this case. The MAOP compliance remedy for this pipeline involves reducing the operating pressure on the line from its current operating pressure to the pressure documented in the records used to establish MAOP via 49 CFR 192.619(c). The Line 1080 segment being addressed does not require reconfirmation of MAOP per 49 CFR 192.624, as it does not meet the definition of a covered segment.[25] The Company has adequate documentation to operate the line at the lower pressure per 49 CFR 192.619(c) and needs to augment the system to enable the operation of this line at the lower pressure, so customers are not at risk of losing service. The Company plans to keep the existing pipeline in service and augment the distribution system by constructing a 6.7 mile parallel main.

Line 1080 is a single feed system that serves approximately 19,000 customers. It is comprised primarily of 8" diameter high-pressure steel which operates at >20% Specified Minimum Yield Strength. This line was primarily installed in the 1950s. It runs west out of the M Avenue City Gate, feeding the local communities west of the City of Kalamazoo. The Line 1080 project completed survey and field investigations during 2022. Project planning and city gate facility upgrades were completed in 2023. Project milestones during 2024 include acquisition of real estate, completion of construction plans, delivery of long lead time materials, and issuing requests for construction bids. Construction contracts are expected to be executed early in 2025 so that actual construction

[25] Provisions that grandfather the documentation requirements for Line 1080, and the fact that pressure test records are not missing for this segment explain why Line 1080 is not a "covered segment".

will take place during 2025. The Company plans to improve the resilience of the system in the area served by Line 1080, which has limited sources of supply, by constructing a 6.7 mile 12" diameter parallel main to the existing main. Other alternatives considered by the Company (developing loops of main in that area to create connections with additional city gates to provide additional supply locations) to improve resilience were excessive in terms of the cost to construct versus the overall resilience risk reduction.

Q. Please explain the Line 1009 Huron Park to I-94 project.

A. The Line 1009 Huron Park to I-94 project was completed during 2024. This replacement ensures compliance with 49 CFR 192.624 for this half mile segment of 12 inch high pressure steel main. This project is the first phase of four MAOP replacement projects associated with the Line 1009/1009c line segment. The Line 1009 Huron Park to I-94 line segment was originally installed in 1969 and was approximately 55 years old at the time of replacement. It is in Macomb County. The Company determined that pressure testing was not practical and pressure reduction was not feasible for this line segment. To verify the material properties of this segment, the Company would have needed to remove cutout sections of the line. To minimize the impact of pressure testing, pressure reduction, and material testing, the Company believes that it was reasonable and in the best interest of safety, deliverability, and compliance to utilize the replacement option for Line 1009 Huron Park to I-94.

Q. Please explain the Line 1009/1009c I-94 to Little Mack/10 Mile to 11 Mile project.

A. The Line 1009/1009c I-94 to Little Mack/10 Mile to 11 Mile project scope includes 1.53 miles of 12" diameter main installation to replace the existing 10" diameter main. It is the second phase of four phases of MAOP replacement for the Line 1009/1009c line segment. The Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile project line segment was installed in 1969 and is approximately 55 years old. It is in Macomb County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile. This second phase of the Line 1009/1009c replacement is currently in the design phase of project development and will be constructed during 2025.

Q. Please explain the Line 1022f Vermontville project.

A. The Line 1022f Vermontville project scope includes 0.038 mile of 8" diameter main installation to replace a similar sized existing main segment. The existing Line 1022f Vermontville line segment was installed in 1982 and is approximately 42 years old. It is in Eaton County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line. To minimize the impact of pressure testing, pressure reduction, and material testing it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1022f Vermontville project. The Line 1022f Vermontville project is currently in the planning and design phase of project development and will be constructed during 2025.

Q. Please explain the Line 1002f Macomb ITC Corridor project.

A. The Line 1002f Macomb ITC Corridor project scope includes 0.07 mile of 26" diameter main installation to replace a similar sized existing main segment. The existing Line 1002f

Macomb ITC Corridor line segment was installed in 1971 and is approximately 53 years old. It is in Macomb County. The Company has determined that pressure testing is not practical and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line. To minimize the impact of pressure testing, pressure reduction, and material testing it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1002f Macomb ITC Corridor project. The Line 1002f Macomb ITC Corridor project is currently in the design phase of development and will be constructed during 2025.

Q. Please explain the Line 1020 Greenfield Road project.

A. The Line 1020 Greenfield Road project scope includes 0.038 mile of 12” diameter main installation to replace a similar sized existing main segment. The existing Line 1020 Greenfield Road line segment was installed in 2006 and is approximately 18 years old. It is in Oakland County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1020 project. This project is currently under construction during 2024.

Q. Please explain the Line 1087b East and West Segment projects.

A. The Line 1087b East and West Segments project scope includes 0.81 mile of 12” diameter main installation to replace an existing 8” diameter existing main segment. The majority of this line segment was installed during the 1970s and a small section was installed during the 1990s. It is in Midland County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1087b East and West Segments project. This replacement project will be constructed in two phases. Each phase is currently in the design phase of development and construction is planned to occur during 2025.

Q. Please explain the Line 1009/1009c Phase 3, 9 Mile to 10 Mile project.

A. The Line 1009/1009c Phase 3, 9 Mile to 10 Mile project scope includes 1.3 miles of 12" diameter main installation to replace a similar sized existing main segment. The existing Line 1009/1009c Phase 3, 9 Mile to 10 Mile line segment was installed in 1969 and is approximately 55 years old. It is in Macomb County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this line segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1009/1009c Phase 3, 9 Mile to 10 Mile project. The Line 1009/1009c Phase 3, 9 Mile to 10 Mile project is currently in the planning phase of project development. Design work is planned for 2025, and construction is planned for 2026.

Q. Please explain the Line 1002c project.

A. The Line 1002c project scope includes 8.15 miles of 24" diameter main installation to replace a similar sized existing main segment. The existing Line 1002c line segment was primarily installed in 1959 and 1960 and is more than 60 years old. It is in Oakland County. The Company has determined that pressure testing is not practical due to the length of the line segment that needs to be reconfirmed and pressure reduction is not feasible given gas deliverability requirements on the high-pressure system. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1009c project. The Line 1002c project is currently in the planning phase of project development. Design work will occur during 2025, and construction is planned to occur in phases starting in 2026 and ending in 2029.

Q. Please explain the Line 1022 Airport City Gate to State Rd and State Rd to W Grand River project.

A. The Line 1022 Airport City Gate to State Rd and State Rd to W Grand River project scope includes 3.5 miles of 16" diameter main installation to replace a similar sized existing main segment. The existing Line 1022 Airport City Gate to State Rd and State Rd to W Grand River was primarily installed in 1963 and is more than 60 years old. One additional segment was installed in 1980 and is more than 40 years old. It is in Clinton County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the

Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1022 Airport City Gate to State Rd and State Rd to W Grand River project. The Line 1022 project is currently in the planning phase of project development, which will conclude during 2025. Design work will also be completed in 2025, with construction planned for 2026.

Q. Please explain the Line 1041 Lapeer Rd project.

A. The Line 1041 Lapeer Rd project scope includes 3.4 miles of 12" diameter main installation to replace a similar sized existing main segment. The existing Line 1041 Lapeer Rd was installed in 1967 and is approximately 57 years old. It is in Genesee County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1041 Lapeer Rd project. Planning work for the development of this project is planned for 2025, design is planned for 2026, and construction is planned for 2027.

Q. Please explain the Line 1093 Shattuck Rd project.

A. The Line 1093 Shattuck Rd project scope includes 1.76 miles of 12" diameter main installation to replace a similar sized existing main segment. The existing Line 1093 Shattuck Rd was installed in 1967 and is approximately 57 years old. It is in Saginaw County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1093 Shattuck Rd project. The Line 1093 Shattuck Rd project is currently in the planning phase of project development, with design work planned for 2025 and construction planned for 2026.

Q. Please explain the Line 1006 Groebel Dr to Mound Rd project.

A. The Line 1006 Groebel Dr to Mound Rd project scope includes 0.31 mile of 24” diameter main installation to replace a similar sized existing main segment. The existing Line 1006 Groebel Dr to Mound Rd was installed in 1959 and is approximately 65 years old. It is in Macomb County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1006 Groebel Dr to Mound Rd. The Line 1006 Groebel Dr to Mound Rd project is currently in the planning phase of development, with design work planned for 2025 and construction planned for 2026.

Q. Please explain the Line 1026f Mt Hope project.

A. The Line 1026f Mt Hope project scope includes 0.758 mile of 8” diameter main installation to replace a similar sized existing main segment. The existing Line 1026f Mt Hope was installed in 1998 and is approximately 26 years old. It is in Ingham County. The Company has determined that pressure testing is not practical, and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1026f Mt Hope project. The Line 1026f Mt Hope project is currently in the planning phase of project development, with design work scheduled for 2025 and construction planned for 2026.

Q. Please explain the Line 1026i MSU PP project.

A. The Line 1026i MSU PP project scope includes 0.133 mile of 8" diameter main installation to replace a similar sized existing main segment. The existing Line 1026i MSU PP segment was installed in 1970 and is approximately 54 years old. It is in Ingham County. The Company has determined that pressure testing is not practical and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing; it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1026i MSU PP project. The Line 1026i MSU PP project will begin the planning phase of development in 2025, with design work planned for 2026 and construction planned for 2027.

Q. Please explain the Line 1090n Davis St project.

A. The Line 1090n Davis St project scope includes 0.012 mile of 8" diameter main installation to replace a similar sized existing main segment. The existing Line 1090n Davis St segment was installed in 2002 and is approximately 22 years old. It is in Tuscola County. The Company has determined that pressure testing is not practical and pressure reduction is not feasible for this segment. To verify the material properties of this segment, the Company would need to remove cutout sections of the line for the purpose of destructive testing. To minimize the impact of pressure testing, pressure reduction, and material testing it is in the best interest of safety, deliverability, and compliance to utilize the replacement option for the Line 1090n Davis St project. The Line 1090n Davis St project construction was completed during 2024.

Q. Please describe the Cathodic Protection Distribution sub-program within the Regulatory Compliance Program and the associated projections included in this filing.

A. As shown on Exhibit A-103 (LDW-4), line 4, the capital expenditures for this sub-program were $12,391,559 in 2023, and are projected to be $11,013,242 in 2024; $8,232,359 for the ten months ending October 31, 2025; and $9,800,115 for the 12 months ending October 31, 2026, as set forth on this exhibit on line 4, column (b); line 4, column (c); line 4, column (d); and line 4, column (f), respectively. Table 13 above also shows the capital expenditures for the Cathodic Distribution sub-program.

The capital expenditures include a combination of impressed current installations (new and replacements), galvanic (sacrificial) anode installations, and the replacement of services or mains to clear shorted sectors. Exhibit A-103 (LDW-4), line 4, provides further details of the expenditures included in this program.

Q. Please describe the need for the Company to make capital investments in impressed current installations.

A. The impressed current installations include a combination of rectifier installations (new and replacements) and impressed current groundbed installations (new and replacements). The impressed current systems (rectified) consist of an external DC power source that supplies power to anode beds installed below grade. These impressed current systems include a combination of conventional groundbeds (surface beds), semi deep groundbeds (20 feet to 150 feet deep), and deep anode systems (greater than 225 feet in depth). The Company continues to install impressed current systems (rectified systems) and remote monitoring units ("RMUs"). The rectified systems allow the Company more control of system performance by having the ability to adjust the amount of current being applied to the system. The installation of RMUs allows the Company to monitor the output of rectifiers remotely.

Q. What is the status of the Company's installation of remote monitoring units?

A. The Company plans to complete the installation of 336 RMUs during the 2024 calendar year, in addition to the 559 that are already in service. The RMU installations are going to be complete during 2024.

Q. What are the benefits that will be realized as a result of the Company's installation of RMUs?

A. Statewide, distribution corrosion has a total of 896 rectifiers that must be read every two months, six times per calendar year. Historically these bi-monthly reads had to be read manually. The installation of RMUs reduces the number of required physical visits of each rectifier to one visit per year. This will help reduce the environmental impact of driving to each of these rectifiers and will keep operating and maintenance costs down. Additionally, the RMU installations allow the Company to receive notifications when the rectifiers are not outputting correctly, diagnostic work can then be initiated quicker, which improves the integrity and reliability of the distribution system. RMU devices also allow for the Company to remotely interrupt rectifiers to perform cathodic surveys and testing.

Q. Please describe the need for the Company to make capital investments in galvanic anode installations.

A. Galvanic anode systems protect natural gas mains from corrosion using 17-pound and 20-pound magnesium anodes that are installed near a gas main. These anodes attract naturally occurring corrosion that would otherwise cause cracks, leaks, and other dangerous safety hazards in gas distribution mains. Replacement of existing magnesium anodes is necessary when annual surveys and associated diagnostics indicate the existing anodes have depleted. The installation of new galvanic anodes is necessary when the current output no longer provides an adequate level of cathodic protection to the pipeline.

Q. Please describe the need for the Company to make capital investments in services or mains within the Cathodic Protection Distribution program.

A. Annual surveys of services and mains are conducted to identify any segments that have experienced corrosion to the extent that replacement is required to maintain safety and reliability.

Q. Please describe the need for the Company to make capital investments in casing test points?

A. The cathodic protection system requires an adequate number of test points for cathodic protection application and monitoring. Casing test point reads are required to be read on an annual basis to ensure casing and carrier pipe are not electrically continuous. Casings that have been identified in the Company's mapping systems and corrosion databases, which do not have an active test point, are being excavated, a test point is installed, and test points are read to ensure electrical discontinuity between casing and carrier pipe.

Q. What Federal and State regulatory standards make it necessary for the Company to invest in the Cathodic Protection Distribution sub-program?

A. The applicable Federal and State regulatory standards include Michigan Gas Safety Standards Section Three, Subpart I which is titled "Requirements for Corrosion Control". Within Subpart I, Section 192.463 is titled "External corrosion control: Cathodic protection". Similarly, Federal standards include Title 49 of the Code of Federal Regulations, subtitle B, chapter 1, subchapter D, part 192, subpart I, which is also titled "Requirements for Corrosion Control".

Q. What amount has the Company historically invested in the Cathodic Protection Distribution sub-program?

A. The Company invested $39.654 million in the Cathodic Protection Distribution sub-program during 2019-2023. The annual investment averaged $7.931 million per year over that time period. Annual amounts for each year were:

- 2019 historical actual: $5,039,720;
- 2020 historical actual: $6,663,545;
- 2021 historical actual: $6,976,687;
- 2022 historical actual: $8,582,806;
- 2023 historical actual: $12,391,559;
- 2024 projected: $11,013,242;

- 2025 projected: $9,535,994; and
- 2026 projected: $9,840,093.

Q. What portion of the historical and projected investments in the Cathodic Protection Distribution sub-program represent investments in RMU Installations?

A. The Company invested $2.494 million in the Cathodic Protection Distribution sub-program during 2019-2023 for RMU Installations. The annual investment averaged $0.499 million per year over that period. Annual amounts for each year are:

- 2019 historical actual: $608,746;
- 2020 historical actual: $532,356;
- 2021 historical actual: $720,208;
- 2022 historical actual: $632,899;
- 2023 historical actual: $0;
- 2024 projected: $791,603;
- 2025 projected: $102,500; and
- 2026 projected: $105,575.

Q. What portion of the historical and projected investments in the Cathodic Protection Distribution sub-program represent investments in Rectifier and Groundbed installations and replacements?

A. The Company invested $8.028 million in the Cathodic Protection Distribution sub-program during 2019 to 2023 for Rectifier and Groundbed installations and replacements. The annual investment averaged $1.606 million per year over that time period. Annual amounts for each year are:

- 2019 historical actual: $1,191,788;

- 2020 historical actual: $1,001,186;
- 2021 historical actual: $1,185,666;
- 2022 historical actual: $2,220,388;
- 2023 historical actual: $2,429,288;
- 2024 projected: $2,705,528;
- 2025 projected: $956,616; and
- 2026 projected: $980,710.

Q. What portion of the historical and projected investments in the Cathodic Protection Distribution sub-program represent investments in other capital repairs?

A. The Company invested $29.132 million in the Cathodic Protection Distribution sub-program during 2019 to 2023 for other capital repairs. The annual investment averaged $5.826 million per year over that time period. Annual amounts for each year are:

- 2019 historical actual: $3,239,186;
- 2020 historical actual: $5,130,002;
- 2021 historical actual: $5,070,813;
- 2022 historical actual: $5,729,519;
- 2023 historical actual: $9,962,271;
- 2024 projected: $7,516,111;
- 2025 projected: $8,476,878; and
- 2026 projected: $8,753,808.

Q. How were the projections for the Cathodic Protection Distribution sub-program developed?

A. Projections for the Cathodic Protection Distribution expenditures are provided by engineering staff within the Gas System Integrity Engineering Department. The test year value was determined using historical calendar month actual experience to include $1,253,635, or 13.15%, of the calendar year 2025 forecast and $8,546,481, or 86.85%, of the calendar year 2026 forecast. The test year total of $9,800,116 is 20.9% lower than the 2023 actual capital investment and is approximately 23.6% higher than the five-year average amount of $7,930,863. The projected increases reflect increasing materials and contractor costs that have been experienced during 2022 and 2023.

The calendar year 2026 forecast for the Cathodic Protection Distribution sub-program is $9,840,093. This forecast includes $0 for RMU installations, $for Rectifier and Groundbed installations and replacements, and $for other capital repairs. The 2026 calendar year forecast is 20.6% lower than the 2023 historical actual investment, and approximately 24.1% more than the 2019 to 2023 historical average. Increasing material and contractor costs are the primary reasons for projections being higher than the historical five-year average.

The calendar year 2025 forecast for the Cathodic Protection Distribution sub-program is $9,535,994. This forecast includes $102,5000 for RMU installations, $956,616 for Rectifier and Groundbed installations and replacements, and $8,476,878 for other capital repairs. The 2025 calendar year forecast is 23.0% lower than the 2023 historical actual investment, and approximately 20.2% lower than the 2019 to 2023 historical average. Increasing material and contractor costs are the primary reasons for projections being higher than the historical five-year average.

The calendar year 2024 forecast of $11,013,242 includes actual expenditures for the January through August period of $6,587,308 and projected expenditures for the September through December period of $4,425,935. The 2024 calendar year forecast is 11.1% than the 2023 historical actual expenditure.

D. Capacity/Deliverability

Q. Please describe the capital expenditures relating to the Distribution Capacity and Deliverability Program as shown on Exhibit A-12 (LDW-1), Schedule B-5.9, line 4.

A. As shown on Exhibit A-12 (LDW-1), Schedule B-5.9, the capital expenditures the Company experienced in 2023, and is projecting for the years 2024, the ten months ending October 31, 2025, and the test year ending October 31, 2026, are $4,445,928; $7,493,075; $7,019,380; and $5,354,075, as set forth on this exhibit on line 4, columns (b) through (f), respectively. The expenditures in the Capacity/Deliverability Program are also shown in Table 18 below:

Table 18: Capacity/Deliverability Capital Expenditures (in Thousands of Dollars)

Program Description	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
Augment	4,446	7,493	7,019	14,512	5,354
Total Capacity/ Deliverability	**4,446**	**7,493**	**7,019**	**14,512**	**5,354**

Exhibit A-104 (LDW-5) provides a detailed breakdown of these expenditures. These capital expenditures reflect needed increases in distribution pipeline capacity, which help ensure adequate pressures for deliverability throughout the system.

Q. Why are Capacity/Deliverability projects necessary?

A. Capacity requirements can change due to shifts in population into new locations, as has been recently experienced in the communities near Macomb, which the Company addressed by the installation of pipe near Huron Point and Selfridge Air Force Base. The Company also continued the augmentation of the medium pressure system in Caledonia in 2020. Further, capacity requirements can increase due to changes in system requirements, as the ways customers use gas change. With the price of the gas commodity remaining relatively low, requests for gas process load, including natural gas-fueled power generation, continue to increase. Substantial requests for additional load, shifts in population and usage, and general system growth cause new low points and bottlenecks to be identified on the gas distribution system. Investment in this program ensures that customers receive reliable gas service even on the coldest days.

Q. Can you describe the process of identifying Augment investments?

A. As described on page 96 of the SEA, the distribution system periodically requires augmentation to adjust for capacity requirements based on current and future gas needs. These projects are identified and prioritized based on gas load analysis software that evaluates system requirements by combining weather conditions (temperature) with known consumption data and system pressures. If the analysis reveals low pressures are expected, the Company will typically install a pressure recording chart to validate the modeled pressures over the next winter. Once validated, an augment project is initiated to reinforce the system, bringing additional capacity or pressure from other parts of the system, to prevent outages or load restrictions to customers. In general, a smaller scope system augmentation project is not planned more than one heating season in advance as they are based upon the system load analysis and actual pressure observations mentioned above.

Q. Please summarize the Augment sub-program investments made by the Company over the past five historical years?

A. Over the time period of 2019 through 2023, the Company has invested over $28.3 million in distribution system Augment projects, as summarized in the following table:

Table 19: Historical Actual Augment Investments by Year

	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Jan - Sep
Caledonia HP Phase 1	$13,613	$488				
Caledonia HP Phase 2	$10,319			-$512		
Caledonia HP Phase 3	$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	0
Imlay City Rd & Lk Pleasant				$1,626,475	-$13,529	
W Sanilac Rd				$1,032,909		
Climax CG					$1,925,844	$45
Walled Lake – Welch & Oak					$1,723,201	-$22,405
Galesburg – Celery & River St.						$1,996,171
Other Projects	$1,811,393	$1,784,195	$2.501,265	$1,514,431	$792,074	$1,332,103
Total Augment	**$3,559,955**	**$3,598,945**	**$6,503,025**	**$10,195,833**	**$4,445,928**	**$3,305,914**

The average historical annual investment for 2019 through 2023 is approximately $5.7 million. The largest project for 2020 was the Caledonia MP Augment Project. This project was chosen to shift supply to the southern area. This was the lowest cost option to serve the area and reduce customer impact. The Gratiot Rd HP replacement was the largest project for 2021. It involved replacement of undersized HP pipe with properly sized main allowing for the station to supply adequate amounts of gas to the Macomb area. The Shaffer Rd East Alamando project was the largest project for 2022. This project also involved the replacement of undersized HP pipe with properly sized main, which will increase the supply of gas to an area north of Midland. The Climax City Gate project is the largest augment project constructed during 2023. The construction of this project was necessary to increase the capacity of the system serving areas to the north of Climax extending to the Gun Lake area.

Q. Can you describe the Augment investments included in this filing?

A. There are several projects planned for 2024 through 2026 to reduce bottlenecks on the system. These are intended to provide capacity and resiliency outside the Galesburg City Gate (the Celery and River Street project high pressure main installation) and Coleman-Beaverton City Gate (the Shaffer Road and Beaverton projects high pressure main installation). These projects as well as several other smaller projects will require a projected total investment of $20.5 million over that time period.

Examples of augmentation projects currently planned for 2024 through 2026 include:

- Connecting the existing medium pressure distribution system to a new outlet at the Orion City Gate requires construction of approximately 1100 feet of six-inch medium pressure plastic main. The connection to the new outlet enhances capacity and resilience in an area where growth could create low pressure conditions. This project is planned for completion by November 2024.

- A project is planned to install approximately 1700 feet of four-inch plastic medium pressure main on Rives Junction Road and 1300 feet of two-inch medium pressure plastic main on Parnall Road in the Jackson area to construct a looped gas supply to reduce risks of low pressure as well as improve resilience on this main. The project is planned for construction during 2026.

- A project is planned to install approximately 1100 feet of six-inch plastic medium pressure main on Belsay Rd that connects with existing two-inch medium pressure main on Burton Estates Drive east of Flint. This project will address low pressure conditions experienced during the winter of 2022-2023, and improve resilience in this area. Construction is planned to occur during 2025 for this project.

- The Beaverton Shaffer Road east of Alamando project involves the construction of 7050 feet of 12-inch steel high pressure main that will be constructed parallel to existing six-inch high pressure main out of the Coleman Beaverton City Gate station. This capacity expansion will improve delivery pressure in an area of growing demand. This project is planned for construction during 2025.

- The Crooked Lake Road - Latson Road project will construct 3,000 feet of six-inch medium pressure plastic main to create a looped system near the end of two existing distribution main systems. This augment project will improve deliverability by creating a back feed and increase the system pressure. The resilience of the system will also be enhanced by the looped system. This project completed construction during 2024.

- The Galesburg - Celery & River Street project will construct 6,900 feet of eight-inch high pressure steel main from the Galesburg city gate outlet to Comstock Avenue & Celery Street in the Kalamazoo area. This will create a looped system from the Galesburg City Gate high pressure outlet, increase the delivery pressure and reduce the risk of customer outages due to damage or failure. This project will complete construction before the end of 2024.

Additional augment supply projects are identified each winter as the Company records actual pressure readings and actual temperatures and uses them to further refine the piping system models. These projects tend to be smaller in nature (one mile or less) and therefore less expensive with shorter design and construction timeframes. The Company will continue to review system models and pressures to ensure reliability.

Q. Please describe Exhibit A-105 (LDW-6).

A. Exhibit A-105 (LDW-6), in accordance with Attachment 11 to the filing requirements prescribed in Case No. U-18238, provides the variances in the capital program amounts for the distribution programs which I am sponsoring to the Company's most recent general gas rate case, Case No. U-21490.

Q. Can you explain why columns (c), (e), and (f) of Exhibit A-105 (LDW-6) do not contain any data?

A. Yes, the information for column (c), the "Last Rate Case Approved Spending Plan Case No. U-21490," cannot be provided because Case No. U-21490 resulted in a settlement agreement that did not state approved capital spending amounts for the programs I am representing. Thus, column (c), the "Last Approved Spending Plan" cannot be calculated for those programs. Since there is no data to display in column (c) for these programs, the information for columns (e) and (f), which seek information concerning the variances from (c), cannot be completed.

II. IT PROJECTS

Q. Is the Company planning technology projects that support the engineering, asset planning, design, construction, and maintenance of a safe, reliable, and affordable distribution system for its customers?

A. Yes. Company witness Stacy H. Baker includes in her direct testimony and exhibits a number of technology projects that are critically important in supporting these gas functions within the Company. The expenditures for these projects are contained within the exhibits sponsored by Ms. Baker. The projects for the areas which I am sponsoring are described below:

- The **Gas Distribution Probabilistic Risk Model** project requires $1,017,283 in capital and $11,030 in O&M in the test year. The project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas distribution pipeline assets. Relative risk models are unit-less measures of risk derived from input information using qualitative data and ordinal scales to produce "risk index" scoring; in simple terms, the relative risk model does not provide true statistical measures. The risk assessment used in the current model provides a score for likelihood, consequence, and risk that is relevant only in comparison to other scores. While the outputs provide a sense of relative risk when comparing one pipeline to another, the scores do not provide quantitative scores for probability, frequency, or expected loss of events. Although pipeline operators commonly use relative risk models, the quality of the relative risk ranking relies on subject matter expert inputs, human inferences, and opinions. Completion of this project will provide value to both the Company and its customers. Each party will benefit from safety improvements and risk mitigation through statistically-based risk modeling that leads to more informed pipeline replacement or improvement projects. Implementing probabilistic risk modeling supports the changes planned for in the Company's NGDP, including the Company's Gas Safety Management System ("GSMS"). GSMS incorporates the Company's plan to implement the American Petroleum Institute ("API") Recommended Practice 1173 (Pipeline Safety Management Systems). Additionally, the implementation of a probabilistic risk model will: (1) calculate quantitative risk scores that include measures of probability, frequency, or expected loss of events; (2) configure multiple data sources to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed decisions based on improved quality inputs in a measurable model; and (3) provide information for better decisions on Capital project improvements and integrity management. Unlike the current unit-less relative model, a probabilistic model will be a unit based risk score, specifically in the unit of dollars, improving efficiency in interpreting risk results for business decisions. The project scope encompasses the implementation of a probabilistic risk model for gas distribution. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) develop reports and dashboards. Alternatives considered for the project include: (1) Implement a custom, Excel based probabilistic risk model through a consulting effort. This alternative was not selected because although the effort minimizes the IT cost of the project, the model requires the creation of secondary data sources, leading to multiple "sources of truth". (2) Implement a custom built probabilistic risk model. This alternative was not selected because the custom built solutions analyzed are not mature and have not been widely tested with transmission operators. (3) Implement a SaaS based solution. The option of implementing the SaaS probabilistic risk model was chosen because it is the most cost-effective long-term implementation approach, providing commercial, off-the-shelf capabilities, industry-proven and upgradable technology, and ongoing vendor support.

- The **Gas Transmission and Distribution ("T&D") Historian** project requires $101,815 in capital and $37,450 in O&M in the test year. The Gas T&D Historian project will replace the current historian for Gas T&D, eDNA (a traditional SCADA historian product from Schneider Electric) and migrate to the standard OSIsoft PI enterprise historian system. The PI system is a suite of software products that are used to collect, store, view, analyze, and share operational data with system users and subject matter experts. The historian for Gas T&D resides on a decades old platform and is not the Company's historian standard. Data access is cumbersome, requires multiple tools to access it, and does not provide for the storing, analysis, or visualization of operational data in a timely manner with appropriate change management control. With the implementation of smart meters, the Company standardized on the more robust OSIsoft PI historian which is used for: (1) Renewable Generation; (2) Electric T&D; and (3) Smart Energy. The Gas T&D historian has yet to be migrated to OSISoft PI, and the eDNA gas data has limited accessibility and usability in its current state and is no longer supported by the vendor. In addition, maintaining the older platform along with the new system requires duplicate resources and skills. This project will create a more accessible and centralized data source with better controls that can be leveraged as the system of record. The project will add value for both Gas Engineering and Gas Operations organizations within the Company by: (1) informing decision-making based on real-time data; (2) improving real-time situational awareness of Operations personnel for information that does not need to be monitored by Gas Control; (3) improving the ability to respond to abnormal situations that do not require immediate intervention through direct communication to Operations personnel; (4) providing information for the development of proactive analytics to reduce potential catastrophic events; (5) streamlining data access through visualization and analytics; and (6) reducing the waste of using multiple interfaces to interpret data. From an IT perspective, consolidating to one standard historian platform will result in savings in hardware, software, maintenance, resources and training. The scope of this project includes: (1) replacing the eDNA Gas T&D historian, a traditional SCADA historian, and migrating to the enterprise historian, OSIsoft PI; (2) developing analytics, visualization and reporting capabilities to support tracking of metrics and making operational decisions; (3) replacing the decades-old Microsoft Access-based custom Daily Gas Reports solution; and (4) retiring the legacy Gas T&D eDNA system (hardware and software). An alternative considered for the project was to upgrade eDNA Gas Historian to the latest version. This option was not selected because it requires a significant investment, and does not meet analytics, reporting, usability and accessibility needs as well as the software owner has announced the "sunset" for this software. Furthermore, the Company standard for historians is OSIsoft PI, and maintaining two platforms results in redundant efforts in training, support personnel, and technology. The option to replace eDNA with the Company standard OSIsoft PI historian was selected to eliminate duplicate training, support personnel, and technology, and to leverage more robust data analytic capabilities in the OSIsoft PI tool set. Currently the plan is to implement the Gas T&D Historian with the Gas SCADA Software Solution to eliminate the need to have duplicative historians while the Gas SCADA Software Solution is being implemented. If this project is not completed, an interruption of operational data reporting capabilities could occur and could result in a non-compliance and could potentially interrupt certain volumetric accounting and billing functions.

- The **Gas SCADA Software Solution** project requires $1,071,858 in capital and $171,959 in O&M in the test year. The Gas SCADA Software Solution project will replace the current Gas SCADA software with a more standardized software package enabling the Company to more efficiently meet Federal and MPSC requirements. The current Gas SCADA software solution was originally implemented in 2000 and was based on the gas system requirements at that time. While the solution has been maintained since its implementation, the Company's gas system has outgrown the current capabilities. As the solution ages, there is increased effort required to address obsolete application and database software architecture, and enhancements to the system are limited. To address the capability gaps, custom interim fixes and integrations have been developed where each requires maintenance and support. This environment adds complexity and cost to solution upgrades and troubleshooting issues. The current Gas SCADA solution will limit the ability to invest in digital solutions for increased system health monitoring and preventative maintenance capabilities due to the complexity to integrate these future capabilities with it. The project will add value by: (1) reducing risk of non-compliance by improving the ability to document and follow State and Federal requirements, improving customer safety; (2) improving efficiency and reliability when performing routine software upgrades, because standard out-of-the-box software has less risk of breaking during upgrades, as opposed to more custom-coded software; (3) reducing maintenance costs due to fewer individual software programs and less custom code; (4) improving Gas Control management capabilities that support the Federal and MPSC requirements for gas pipeline and Gas Distribution companies; (5) improving reliability by using proven gas industry standardized software with configuration features, rather than a fully customized system that has the possibility of being impacted by the next version update; (6) purchasing standard, out-of-the-box software that meets a high percentage of requirements and avoids multiple custom applications and specially coded programs to achieve results; and (7) providing a basis for capturing data required for use in computer-based preventative maintenance programs and more predictive technologies. In addition, implementing industry-specific software helps the collective gas industry users to encourage the vendor development of future version enhancements, which adds more value to gas industry users. The comprehensive Gas SCADA system is used to monitor and control the operating conditions of the transmission and distribution gas systems. The Gas SCADA system includes remote terminal units ("RTUs"), field devices (i.e., valves, meters, odorizers), and computers running SCADA software. This scope covers the Gas SCADA software solution only. The project scope includes the following: (1) significant planning, including consulting assistance, to define the implementation strategy for the effort, given the magnitude of the technology effort; (2) selection and implementation of a new Gas SCADA software solution; (3) planning of a phased rollout of new hardware and software; and (4) retirement and decommissioning of the legacy Gas SCADA solution and equipment once the new system is fully tested and operational. Alternatives considered include: (1) continue to maintain the current solution, at the risk of increasing reliability issues that result in controlling and monitoring the Company's gas system; (2) invest in enhancing the existing Gas SCADA software solution which would introduce additional custom development and more specialized functions that may not be supported in future vendor releases; and (3) replace the solution with a Gas SCADA software solution that meets requirements to support the NGDP. Alternative three has been selected to ensure sustainability for this critical solution. The current legacy system is operating at well beyond its original design specification, so the potential points of failure are not fully known or understood. If the SCADA project is not completed, the legacy system could become unstable and impact Gas Control's ability to operate and monitor real-time system conditions, maintain safe operations, and compliance with regulatory requirements. It could also impact the ability to commission new facilities which require remote monitoring or control or cause the need for 24/7 manual field monitoring of certain facilities.

- The **Tracking and Traceability** project requires $5,295,411 in capital and $508,607 in O&M in the test year. Tracking and Traceability is a project driven from proposed regulatory rules that will require utilities to map new and replacement installations with tracking and traceability data for plastic pipes, fittings, and fusions for the lifetime of the asset. The Company does not currently have a Tracking and Traceability program that will meet PHMSA proposed requirements (PHMSA-2014-0098), also known as the Plastic Pipe Rule. Tracking and traceability refers to the collection of information that provides manufacturing, material type, and location information for pipe and components. PHMSA defines the terms "tracking" and "traceability" as follows: (1) Tracking is information that provides for the identification and location of pipe and components, the date installed, and the person who made the joints in the pipeline system; and (2) Traceability is defined by the American Society for Testing and Materials ("ASTM") standard F2897-11a and includes a unique identifier for the location of manufacture, production lot information, size, material, pressure rating, temperature rating and as appropriate the type, grade, and model of pipe and components. PHMSA will be requiring each pipeline operator to maintain tracking and traceability information for the life of installed pipeline segments. The lack of adequate traceability for plastic pipe and tracking of pipe location prevents gas pipeline operators from having enough information to identify systemic issues related to incidents involving plastic pipe. The lack of this information makes it difficult for operators and regulators to determine whether plastic pipe or component failures are related to a certain type or vintage of material, specific product defect or design, heat/lot of the product, or whether it was produced by a certain manufacturer at a certain time. The lack of information can result in excessive pipe excavations due to an inability to locate the affected sections of pipe or fittings when responding to plastic pipe or component manufacturer recalls. This project will develop a sustainable Tracking and Traceability program that will meet PHMSA requirements (PHMSA-2014-0098) which address the proposed tracking and traceability requirements. The project adds value by capturing traceability data via barcode readers and location tracking information via Global Positioning System (or "GPS") equipment to improve the quality of data and assist the Company in determining future scopes of work in the event of any component manufacturer recalls. The scope of work will include:

(1) changes in SAP Supply Chain processes to capture the required barcode information for all plastic components used in gas distribution and service lines; (2) changes in SAP Work Management processes to account for capturing barcode information as part of material components added to work orders, capturing fusion information from work order completion and capturing GPS coordinates from work order completion; (3) changes in GIS to capture GPS coordinates of plastic components and GPS coordinates of component fusions; (4) building of a repository for tracking and traceability reporting and analysis; (5) purchasing barcode reading equipment for storerooms and gas distribution trucks; and (6) purchasing of GPS locating equipment to capture coordinates. Alternatives considered include: (1) The do nothing alternative, which was not selected because it would expose the company to significant legal and financial risk resulting from non-compliance; and (2) Internally develop digital technology that will support the tracking and traceability standards included in the PHMSA-2014-0098 plastic pipe rule. The second alternative is being pursued by the Company.

Q. Please summarize your direct testimony.

A. My direct testimony describes the Company's Gas Distribution capital investment requirements for specific programs that are required to operate a gas distribution system that is safe and reliable. The projections included in this testimony are needed to meet customer capacity demand and regulatory requirements, reduce leaks on the system, and protect public safety. I have described the importance of project coordination with other public infrastructure work as recognized by the MPSC through the SEA and the Michigan Infrastructure Council and demonstrated the Company's commitment to this coordination. The Company's NGDP will work to enhance the Company's gas distribution system and offer additional opportunities for similar collaboration with municipal partners. Through the implementation of the NGDP and the execution of the projects outlined in my direct testimony above (including the IT projects that support these distribution system projects), investments that are both reasonable and necessary, the Company can provide a safe, reliable, affordable, and clean gas delivery system for its customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.